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Subject: **Submittal of ABWR Licensing Topical Report (LTR) NEDO-33335 "Plant Medium Voltage Electrical System Design"**

Reference: Letter MFN 017-97, J. Quirk to NRC, *ABWR Design Control Document, Revision 4*, dated March 28, 1997, Docket No. 52-001

This Licensing Topical Report (LTR) is one of a series of ABWR-related LTRs GE plans to submit and which have been discussed in South Texas Project (STP) 3&4 project meetings with the NRC. In support of the ABWR Design Centered Working Group (DCWG) plans, GE requests a generic review and approval of the subject Licensing Topical Report (LTR) in advance of any future combined license application (COLA) submittals. Note that the submittal is the result of design detailing performed for ABWRs in the US and in Asia and contributes to standardization. In particular, this LTR identifies proposed changes to the plant medium voltage electrical system.

The scope of proposed changes identified by this LTR relate to the DCD Tier 2 single medium voltage (MV) design requirements in the ABWR certified design. The proposed changes to the MV electrical system provide for an alternate approach to the system design that allows greater flexibility in equipment procurement without any negative effect on design basis assumptions. The proposed changes to the certified design are based on a dual medium voltage electrical system in lieu of a single 6.9 kV system. An exemption from the generic Technical Specifications is necessary to implement the DCD Tier 2 changes. The certified design material in DCD Tier 1 is not affected.

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Currently, 10 CFR Part 52 does not permit generic changes in design certifications, except for limited purposes that are not applicable in this case. However, as identified in SECY-06-0220 and the associated Staff Requirements Memorandum dated April 11, 2007, the NRC is planning to revise 10 CFR 52.63 to allow for certain types of changes to a design certification. Therefore, GE is providing LTR Appendix A to address the anticipated and preferred regulatory path of DCD amendment, so that the NRC technical review can proceed in parallel while the regulatory environment matures. The appendix demonstrates that the proposed addition is acceptable as a generic change to the DCD under the pending revision to 10 CFR 52.63.

Should the NRC determine otherwise, the enclosed LTR should be considered as a generic submittal that, if approved, would allow future applicants to reference the LTR as a basis for a departure from the DCD. Appendix A to the LTR provides the justification for the departure under Section VIII.B.5 of the ABWR design certification rule.

The enclosure contains no information that GE considers proprietary although full copyright protection applies.

If you have any questions about the information provided here, please contact me at 910-602-1885.

Sincerely,

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Enclosure: NEDO-3333 "Plant Medium Voltage Electrical System Design", May 2007 – Non-Proprietary

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LICENSING TOPICAL REPORT

Advanced Boiling Water Reactor (ABWR) Plant Medium Voltage Electrical System Design

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Table of Contents

1.0 Introduction 1
2.0 Description of Design Certification 1
3.0 Description of the EDS with Dual MV Design 3
4.0 Description of Proposed Changes 5
5.0 Justification for Tier 2 Changes 6
6.0 Detailed Design Experience 10
7.0 Description of the Dual Medium Voltage EDS 10
8.0 Nuclear Safety Review 10
9.0 Consistency with ABWR Design Control Document (DCD) 12
10.0 Consistency with RG 1.206 12
11.0 Description of DCD Markups 12
12.0 Conclusions 12
13.0 References 13
Appendix A–JUSTIFICATION FOR CHANGES TO THE GENERIC DCD 14
Appendix B - ABWR DCD/TIER 2 & TS MARKED CHANGES 15

1.0 Introduction

This Licensing Topical Report (LTR) requests US Nuclear Regulatory Commission (NRC) approval of a generic change to the design certification for the U.S. Advanced Boiling Water Reactor (ABWR) design. The proposed changes involve conversion of the medium voltage (MV) Electrical Distribution System (EDS) from a single 6.9 kV system to a dual 13.8 kV/4.16 kV system. An exemption to the generic Technical Specifications (TS) is necessary to implement the proposed changes. In addition to the dual voltage change, the changes include higher MVA and voltage rating of the Combustion Turbine Generator (CTG), addition of a reserve auxiliary transformer (RAT) and larger emergency diesel generator (EDG), main power transformer (MPT), unit auxiliary transformer (UAT) and RAT ratings. The proposed changes were developed during performance of first-of-a-kind-engineering for the ABWR.

The proposed changes allow the plant electrical system to be designed/built in a manner that meets NRC requirements and allows greater flexibility to equipment procurement without any negative effect on design basis assumptions.

For the reasons discussed in Section 8.0 of this LTR, the changes proposed in this LTR would not affect the Probabilistic Risk Assessment (PRA) conclusions.

2.0 Description of Design Certification

The MV distribution system switchgear (both Class 1E and non-Class 1E) are rated at 6.9 kV. The Class 1E EDG are rated at 6.9 kV and connected to their respective 6.9 kV Class 1E buses. The non-Class 1E CTG is rated at 6.9 kV and connected to the plant investment protection (PIP) buses and Class 1E buses.

The onsite power system interfaces with the offsite power system at the input terminals to the supply breakers for the normal, alternate, and CTG power feeds to the MV (6.9 kV) switchgear. The offsite power is supplied to the plant loads through three UATs and one RAT. The RAT is a true reserve transformer since unit startup is accomplished from normal preferred power (NPP) through UAT. Refer to Figure 1 for the design certification EDS configuration.

The onsite power system is a three loadgroup system with each load group consisting of a non-Class 1E and a Class 1E portion. The three load groups of the Class 1E power system (i.e., the three divisions) are independent of each other.

The non-Class 1E medium voltage power distribution system consists of nine 6.9 kV buses divided into three load groups. The three loadgroup configuration was chosen to match the mechanical systems which are mostly three trains.

Within each load group there are two power generation (PG) buses and one PIP bus. These PG buses normally receive power from their assigned UAT and supply power to the third bus (PIP bus) in the load group through a cross-tie. The cross-tie automatically opens on loss of power but may be manually re-closed if it is desired to operate a condensate and feedwater pump or a condensate pump from the RAT which is connectable to the PIP buses. In addition, the CTG is

capable of supplying power to any of the condensate pumps through the bus ties from the PIP buses.

This provides three load groups of non-Class 1E grade equipment, in addition to the divisional Class 1E load groups, which may be used to supply water to the reactor vessel in emergencies.

Class 1E AC power loads are divided into three divisions (Divisions I, II, and III), each fed from an independent 6.9 kV Class 1E bus. During normal operation (which includes all modes of plant operation; i.e., shutdown, refueling, startup, and run), two of the three divisions are fed from an offsite NPP supply. The remaining division is fed from the alternate preferred power (APP) source. This division is immediately available, without a bus transfer, if the NPP is lost to the other two divisions.

The Division I, II, and III standby AC power supplies consist of an independent 6.9 kV Class 1E EDG, one for each division. Each EDG may be connected to its respective 6.9 kV Class 1E switchgear bus through a circuit breaker located in the switchgear.

Three non-Class 1E buses and one Class 1E division receive power from the single UAT assigned to each load group. Load groups A, B and C line up with Divisions I, II and III, respectively. One winding of the RAT may be utilized to supply reserve power to the non-Class 1E buses either directly or indirectly through bus tie breakers. Any one of the three Class 1E buses may be supplied power from the other winding of the RAT.

The CTG supplies automatic standby power to PIP loads. These loads are grouped on the three PIP buses. The CTG also has the capability to be manually connected to any of the three Class 1E buses, for mitigation of the station blackout (SBO) event.

The plant 480 VAC power system distributes sufficient power for normal auxiliary and Class 1E 480 volt plant loads. All Class 1E elements of the 480V power distribution system are supplied via the 6.9 kV Class 1E switchgear and, therefore, are capable of being fed by the normal preferred, alternate preferred, standby diesel generator or CTG power supplies.

The generic TS indicate the Class 1E bus voltage as 6.9 kV. The EDG ratings are indicated as 5000 kW and 6.9 kV. The TS also indicate that the CTG is rated at 6.9 kV and will start and achieve steady state voltage and frequency within 2 minutes.

3.0 Description of the EDS with Dual MV Design

This LTR proposes the EDS with Dual MV Design as described below.

3.1 Introduction

The MV distribution system switchgear (both Class 1E and non-Class 1E) of ABWR EDS consist of two voltage systems, 13.8 and 4.16 kV. The PG switchgear are rated at 13.8 kV. The PIP and Class 1E switchgear are rated at 4.16 kV. Three Class 1E EDGs are rated at 4.16 kV and connected to their respective 4.16 kV Class 1E buses. The non-Class 1E CTG is rated at 13.8 kV and is connected to the 13.8 kV PG buses. The CTG is also connected to the PIP and Class 1E switchgear buses through a 13.8 kV/4.16 kV step down transformer.

3.2 Description

The onsite power system interfaces with the offsite power system at the input terminals to the supply breakers for the normal, alternate, and CTG power feeds to the MV switchgear. The offsite power is supplied to the plant loads through three UATs and two RATs. (Refer to Figure 2).

Two of the UATs and the two RATs are three winding transformers with secondary windings rated at 13.8 and 4.16 kV. The third UAT is a two winding transformer with the secondary winding rated at 4.16 kV. The RATs are true reserve transformers, each with rated capacity to replace any one of the UATs.

There are four PG buses that are configured to meet the requirements that the ten reactor internal pumps be powered by four independent buses to minimize large core flow reduction events and to match the mechanical systems which are mostly four trains (e.g. four feedwater pumps, four circulating water pumps, four condensate pumps, four condensate booster pumps, four heater drain pumps).

The NPP to each two of the four PG buses is fed from one UAT through direct connection to its 13.8 kV winding. In case of loss of NPP, the affected PG buses can receive APP from the RATs through intermediate non-Class 1E 13.8 kV switchgear buses. Each RAT can supply APP power to two PG buses.

There are three PIP buses that are configured to match the mechanical systems that consist of either two or three trains. Each PIP bus is fed from one UAT through direct connection to its 4.16 kV winding. The same UAT 4.16 kV winding is directly connected to the corresponding Class 1E division bus through a stub bus. The PIP buses are also directly connected to RAT (A) 4.16 kV winding as a source of APP supply. The same RAT (A) 4.16 kV winding is directly connected to the Class 1E buses through stub bus.

The Division I, II, and III standby AC power supplies consist of an independent 4.16 kV Class 1E EDG, one for each division. Each EDG may be connected to its respective 4.16 kV Class 1E switchgear bus through a circuit breaker located in the switchgear.

During normal plant operation all of the non-Class 1E buses and two of the Class 1E buses are supplied with power from the main turbine generator through the UATs. The remaining Class 1E bus is supplied from RAT (B). This division is immediately available, without a bus transfer, if the NPP is lost to the other two divisions.

The CTG can supply AC power through intermediate non-Class 1E 13.8 kV buses to any one of the PG buses to feed one of the condensate pumps. The CTG also supplies standby power to any of the PIP buses through an intervening 13.8/4.16 kV transformer. In addition the CTG can supply standby power to any of the Class 1E buses through the same 13.8/4.16 kV transformer in case of failure of all the NPP, APP and EDG power supplies.

The plant 480 VAC power system distributes sufficient power for normal auxiliary and Class 1E 480 volt plant loads. All Class 1E elements of the 480V power distribution system are supplied via the 4.16 kV Class 1E switchgear and, therefore, are capable of being fed by the normal preferred, alternate preferred, standby diesel generator or CTG power supplies.

4.0 Description of Proposed Changes

The following is a summary list of Tier 2 design changes proposed for the DCD, including changes from single MV to the proposed dual MV design;

1. Change the MV distribution system from a single 6.9 kV system to a dual 13.8 kV/4.16 kV system.
2. Change the PG buses to 13.8 kV.
3. Change the Class 1E and PIP buses to 4.16 kV.
4. Add stub buses for the connection between the RATs and the Class 1E buses.
5. Provide two RATs instead of one RAT.
6. Add provision of a power source for an electric boiler (optional).
7. Provide a 13.8 kV CTG with an increased rating of at least 20 MWe from 9 MWe.
8. Change EDG voltage rating from 6.9 kV to 4.16 kV and increase EDG size from 6.25 MVA @ 0.8 power factor to 9 MVA @ 0.8 power factor (5000 kW to 7200 kW).
9. Provide larger RAT and UAT transformer capacities and revised configuration.
10. Provide for larger capacity main power transformer (MPT) (1612 MVA versus 1500 MVA).
11. Add 13.8/4.16 kV transformer to feed the 4.16 kV Class 1E and non-Class 1E loads from the 13.8 kV CTG.

The following is a summary list of changes to the TS and its Bases sections:

1. Change the medium voltage rating of the Class 1E buses to 4.16 kV.
2. Change the EDG ratings to 7200 kW and 4.16 kV.
3. Change the CTG voltage rating to 13.8 kV.
4. Change the time required for CTG to start and achieve steady state voltage and frequency to "in less than 10 minutes" from "2" minutes.

Appendix B provides a markup of DCD Tier 2 and TS changes resulting from these proposed design changes. Figure 2 provides a single line diagram of the proposed changes to the EDS and large pump feeds.

The performance characteristics of the proposed changes are an improvement to the design certification. The motor driven main feedwater pump and large circulating water pump motors, using a 6.9 kV system would have had to be designed with very high current ratings switchgear buses, breakers and feeder cables. An additional RAT will provide a total of three paths from which to power the Class 1E buses from offsite power.

The proposed alternate dual MV EDS design is more reliable compared with the design certification.

The DCD accident analyses are not affected by the proposed design. The changes to the DCD do not affect the DCD evaluation methodology. The proposed changes are consistent with DCD Tier 1 requirements.

5.0 Justification for Tier 2 Changes

The proposed changes to the design certification are justified (see Appendix A) based on the following:

5.1 Design Justifications:

5.1.1 The DCD Tier 2 MV EDS only contains the initial values and ratings for system performance. The MV electrical system could not have been built in the DCD configuration (number/arrangement of buses and transformers and equipment ratings) with standard product line switchgear or standard product line protection schemes and still meet the requirements for voltage regulation and fault current interruption. The proposed revision will follow current design practice and regulatory requirements similar to existing analyzed international design.

5.1.2 Changing the PG buses to 13.8 kV allows retaining the minimum required four buses (and their required breakers) because normal and fault currents are halved. Similarly there will be some plants whose circulating water pumps and/or cooling towers are up to one mile from the turbine/switchgear building and the higher voltage will reduce their cabling, breaker and duct bank costs and starting motor impact on voltage regulation.

5.1.3 Adding stub buses allows accommodating the NRC required "direct connection to transformers" while providing transformer differential current protection. The proposed MV design always has either a stub bus or non-Class 1E bus between any UATs or RATs and the Class 1E buses to improve transformer protective relaying. The stub buses do not supply any other load than the Class 1E buses. The UATs and RATs supply preferred power to the Class 1E buses and their reliability is important for both power generation and safety. One of the most important transformer protection schemes is differential relaying. This protective relaying concept measures current into and out of each transformer summing the various windings and correcting for voltage (current ratio). If the input/output currents do not sum to zero, it is evidence of a transformer internal fault and can be detected with much greater sensitivity (and speed) than absolute current measurements.

The original MV design in the DCD has a direct connection between the RAT and the Class 1E buses without an intervening non-Class 1E bus. This would have caused a situation where one current transformer was on the transformer inlet and three current transformers (one per Class 1E bus) on the transformer output. Not only would the three Class 1E buses have been connected together through the current transformers and thereby reduced their independence, a measurement fault on one division would have resulted in the loss of that transformer feed to all divisions. Additionally either the current transformers on the Class 1E bus would have been non-Class 1E or isolators would have to have been furnished with a frequency response that captured events within an

electrical cycle (along with very high accuracy) - or the transformer protection deleted. These choices are either not possible or do not meet standard electrical system protective relaying practice. By interposing a stub bus, the protective relaying can be all non-Class 1E and the transformers adequately protected. The feeds to the Class 1E buses can be protected with absolute current measurements without connecting Class 1E and non-Class 1E current transformers. The proposed scheme both improves reliability and divisional isolation and independence.

5.1.4 Providing two RATs improves the reliability of offsite power sources to the PG, PIP, and Class 1E buses.

5.1.5 Provides a power source for an optional electric auxiliary boiler which is not in the original DCD configuration.

5.1.6 Provides for a CTG with enough capacity to operate as required for any combination of two PIP or two Class 1E buses and the buses to support the CTG and its auxiliaries; as a corollary, provides an electrical configuration that can support the additional CTG fault current contribution.

5.1.7 Still provides for a CTG and connections that support the condensate pump operation in a SBO.

5.1.8 Provides the necessary RAT and UAT transformer capacities that support the required loads and an electrical configuration that can support their fault current contribution at reasonable impedances that, in turn support required voltage regulation.

5.1.9 Provides for electrical system bus configurations that provide operating flexibility for both outages and normal operation. The proposed dual MV design improves flexibility by providing multiple sources of power to the various buses for normal, outage, accident and severe accident conditions. For example, the interconnecting breaker between the two 13.8 kV CTG buses allows either of the RATs to supply any of the PG buses or the PIP or Class 1E buses. In the case of multiple units the inter-unit connection of the CTG bus allows the other unit's RATs or CTG to be another source of power to the PIP and Class 1E buses for both severe accidents and station blackouts. The addition of a second RAT allows all of the UATs to be taken out of service simultaneously during an outage and vice versa. Finally the arrangement allows the CTG to power any of the condensate pumps to satisfy PRA requirements and possibly two condensate pumps with the inter-unit connection.

5.1.10 Changed the EDG voltage from 6.9 kV to 4.16 kV to match the Class 1E bus voltage. The increased EDG size is in part because of the increased size of motors required such as High Pressure Core Flooder (HPCF) pumps and reactor building service water pumps

5.1.11 The changes proposed in this LTR will have no effect on GE's evaluation of GDC compliance, regulatory guidance and industry codes and standards. The LTR does not deviate from these regulations/guidance or Electric Power Research Institute's (EPRI's) Utility Requirements Document (URD). This LTR will comply with the GDCs, and conform to the regulatory guidance and industry codes and standards provided in NUREG-0800 (SRP Chapter 8).

5.2 Changes to the generic Technical Specifications

Some of the features that are proposed for the MV electrical system are mentioned in the ABWR generic TS Sections 16.3.3, 16.3.5 and 16.3.8 and the Bases for TS Sections B 3.3 and B 3.8. However, the proposed changes do not materially affect any of the discussions in the Bases for TS (see attached mark-ups in Appendix B), except for:

(a) The change from "2" minutes to "in less than 10" minutes CTG startup and availability time,

(b) The change from the single 6.9 kV to the 13.8 kV/4.16 kV dual MV electrical distribution configuration and

(c) Some preliminary voltage values in the Bases for the TS Sections B 3.3 and B 3.8.

GE is seeking an amendment to the DCD for these changes. However, in the event that the revision to 10 CFR 52.63 does not allow for such an amendment, this LTR provides the basis for a COL applicant to request an exemption from the Technical Specifications in accordance with Section VIII.C of the design certification rule and 10 CFR 50.12 (a).

There is no regulatory requirement regarding the 2-minute starting time (currently in the DCD). The 2-minute starting time was established based upon the desire for a "soft" start relative to the starting time for an EDG, and based upon consideration of small CTGs in the 9-MWe size during design certification. The Station Blackout (SBO) Rule (10 CFR 50.63) requires the CTG (alternate ac source) to be available to power the Class 1E buses within 10 minutes of the onset of an SBO. For a large CTG of at least 20 MWe, of the type proposed, the startup sequence is as follows:

1. Duct Purge (Time is dependent on duct volume).

2. Start & Accelerate to Synchronous Idle.

3. Warm up, Synchronize and Breaker Closure.

4. Accelerate to Full Load.

Based upon recent discussions with a reputable and qualified supplier of large CTGs, it is impractical for a CTG of at least 20 MWe size to start in two minutes in contrast to the 9 MWe CTG in the design certification.

Because the startup time will be included in Required Action statements in certain TS Limiting Conditions for Operation (LCOs), we propose a conservative time of < 10 minutes.

The change from a single to a dual MV and other changes to the EDS do not adversely affect the performance of the EDS. The performance characteristics of the subject EDS, as described in this LTR, are better than the current system described in the DCD, due the addition of another RAT.

An exemption to the DCD certification rule is warranted per 10 CFR 50.12 (a) (1), and special circumstances are present in accordance with 10 CFR 50.12(a) (2) (ii), (a) (2) (iv) and/or (a) (2) (vi).

The request for an exemption to the DCD certification rule is justified for the following reasons:

1. 10 CFR50.12 (a) (1): The exemption is authorized by law, will not present an undue risk to the public health and safety, and is not inconsistent with the common defense and security. In particular, the exemption involves design changes only, as described in this LTR. The design changes are not inconsistent with any law. Furthermore, as explained in this LTR, the design changes conform to NRC regulations and applicable standards, and do not adversely affect the function of the EDS. Finally, the design changes do not have any relationship to the design provisions that protect the common defense and security.

2. 10 CFR50.12 (a) (2) (ii): The application of the DCD certification rule for COL applications would not serve the underlying purpose of the rule because a plant based on the design provisions in the original DCD cannot be built using standard product line switchgear or standard product line protection schemes and still meet the requirements for voltage regulation and fault current interruption. It is not necessary to use the design specified in the DCD in order to achieve the purpose of the EDS. Implementation of a dual MV EDS in lieu of a single voltage EDS configuration will accomplish all of the functions of the EDS as specified in the DCD and will therefore achieve the purpose of the EDS.

3. 10 CFR50.12 (a) (2) (iv): The exemption would result in benefit to the public health and safety. As discussed elsewhere in this LTR, the dual MV EDS will provide a more reliable and cost effective plant electrical system, with a higher capacity. This increase in reliability and capacity outweighs the slight safety impacts caused by the increase in the CTG startup and availability time caused by the exemption.

4. 10 CFR50.12 (a) (2) (vi): This LTR demonstrates that there is material circumstance, i.e. experience in designing and building international plants, which suggests that the ABWR plants cannot be built as designed in the original DCD using standard product line switchgear or standard product line protection schemes and still meet the requirements for voltage regulation and fault current interruption. Use of standard products will result in significant cost savings, and the dual MV EDS will result in improvements in reliability and capacity. Therefore, it would be in the public interest to grant an exemption.

6.0 Detailed Design Experience

The design certification uses a single (6.9 kV) MV scheme. The single (6.9 kV) MV electrical distribution configuration in the DCD is impractical to procure and construct. The proposed changes to the EDS are being proposed to accommodate a plant electrical system configuration consisting of three (3) UATs, two (2) RATs, four (4) PG buses, three (3) PIP buses and three (3) Class 1E buses. IEEE 141-1993 provides a rule of thumb that indicates a plant with more than ~20 MVA of plant auxiliary loads should be 13.8 kV. Most plants with this level of loads (dating back as far as Peach Bottom and recently River Bend and the international ABWR plants) use a 13.8 kV system with a 4.16 kV Class 1E system.

7.0 Description of the Dual Medium Voltage EDS

Refer to Figure 2 for a description of the proposed configuration for the Dual Medium Voltage Electrical Distribution System.

8.0 Nuclear Safety Review

The change from the present DCD design to the alternate plant dual MV EDS design will increase plant safety and will improve plant operation, reliability and availability.

As discussed in Section 5.1.3 the proposed scheme both improves reliability and divisional isolation and independence. Improved plant electrical system availability will increase plant safety and reduce risk.

As discussed in Section 5.1.9, the dual voltage design will provide greater flexibility for maintenance, surveillance and/or inspection. This is because of the availability of multiple sources of power to the various buses in the proposed design and the ability to isolate the buses individually, if needed, to perform the required maintenance, surveillance and/or inspection, in accordance with the Maintenance Rule.

The changes to the DCD presented in this LTR do not represent an adverse change to the design function or how design functions are performed or controlled.

The proposed design meets the Class 1E system performance requirements per the ABWR DCD. Furthermore, none of the accident analyses in the DCD are adversely affected by the proposed design.

The changes proposed in this LTR are consistent with GDC requirements. The changes to the DCD do not involve revising or replacing a DCD-described evaluation methodology. System intended functions described in DCD Tier 1 are not affected.

GE has performed a qualitative analysis to determine the impacts of these changes on the PRA. Based upon the factors discussed below, GE has concluded that the changes proposed in this LTR would not affect the conclusions of the PRA.

- As discussed above, the system functions are not affected by this change, and the proposed changes conform to applicable regulations and industry standards referenced in the DCD.

- The proposed changes to the MV electrical system have beneficial impacts upon the PRA analysis results. A slight reduction in risk occurs due to changes in the diversity of the offsite sources feeding the electrical distribution. Adding a second alternate preferred power source (RAT) and the crosstie lead to more paths for success in powering the safety buses. This change results in a decrease in the internal events Core Damage Frequency (CDF). The MV electrical distribution change does not impact the Class 1E electrical distribution three train design as modeled in the PRA. Although there are increased risks associated with increasing the number of components in the system the cumulative analysis of risk concludes the proposed changes have a positive effect on overall risk assessment.

- The proposed changes for the CTG power distribution maintain the assumptions used in the PRA. In the DCD PRA, the CTG was assumed to be able to power a condensate pump and to power the non-Class 1E related PIP buses and the Class 1E buses after a postulated SBO event. In this proposed design, the CTG's ability to power the condensate pump (through the 13.8 KV PG buses), and to power the non-Class 1E PIP and Class 1E buses (through a 13.8/4.16 kV transformer), are maintained. The 13.8/4.16 kV transformer added between the CTG bus and the 4.16 kV buses does not adversely affect the conclusions or results of the PRA.

- The change in CTG startup time from two to <10 minutes does not affect plant safety in the station blackout event since the CTG is not required to provide immediate core inventory or reactor pressure control. With the loss of feedpumps the reactor will scram in seconds on low reactor pressure vessel water level (Level 3) causing an attendant reduction in steaming rate and inventory makeup requirements. Since no makeup is being provided by the normal systems, Reactor Core Isolation Cooling (RCIC) will initiate at Level 2 (whether or not HPCF initiates at Level 1.5) and begin to provide core makeup. RCIC is both automatic and completely independent of alternating current (AC) power and its design basis flow is to provide enough water to prevent core uncovering. Similarly the reactor vessel safety relief valves will automatically operate to control reactor pressure; these valves operate from both accumulator and bottled nitrogen pressure and are completely independent of AC power. The batteries that supply the above power are sized for at least two hours and easily bridge the time until the CTG can start; the CTG startup time is chosen to meet SBO requirements as a nominal ten-minute but the core/vessel is actually protected for much longer periods. As with a loss of coolant accident , over long term the net effect of a SBO event is the heat addition to the suppression pool, but also by design the pool can absorb decay heat for considerably longer than ten minutes of heat addition before Residual Heat Removal shutdown cooling is required. In other roles as used in certain action statements in certain TS LCOs, the critical startup and availability time is <10 minutes.

9.0 Consistency with ABWR Design Control Document (DCD)

The DCD Tier 1 requirements are not affected by the changes described in this LTR. The changes are marked up in Appendix B.

A further detail of proposed changes to the DCD is described in Section 11.0.

10.0 Consistency with RG 1.206

This LTR is consistent with RG 1.206, Sections C.III.1.7 and C.IV.3 guidelines for exemptions from design certification and change processes, respectively.

11.0 Description of DCD Markups

Appendix B contains markups of the Tier 2 DCD pages to reflect the changes proposed in this LTR. The proposed changes are at the same level of detail as the original DCD. The as-built design will be confirmed in ITAAC (DCD Tier 1 Section 2.12, Table 2.12.1).

The bracketed information [ ] in the Technical Specifications are preliminary, pending design detailing and as-built information. These brackets are similar to the brackets that are contained in the generic Technical Specifications in the current DCD.

12.0 Conclusions

Use of the proposed alternate dual MV design and other changes will improve plant safety and reliability and will fully meet the plant electrical system design and performance requirements identified in the ABWR DCD.

The proposed changes to DCD generic TS Sections 16.3.3, 16.3.5 and 16.3.8 and the Bases for TS Sections B 3.3 and B 3.8 to reflect the change from "2" minutes to "<10" minutes CTG startup and availability time, the change from the single 6.9 kV to the 13.8 kV/4.16 kV dual MV electrical distribution configuration and some preliminary voltage values in the Bases for the TS Sections B 3.3 and B3.8 will not adversely affect the safety function of the EDS.

As discussed more fully in Appendix A to this LTR, the proposed changes will promote increased standardization. Therefore, GE requests that the NRC amend the ABWR DCD to incorporate the changes.

If the revision to 10 CFR 52.63(a) will not allow such changes, GE requests that the NRC approve this LTR for use by COL applicants to request an exemption from the DCD on a plant-specific basis.

13.0 References

13.1 ABWR Design Control Document (DCD), Revision 4, Docket No. 52-001.

13.2 SECY-06-0220, Final Rule to Update 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants," October 31, 2006.

13.3 Staff Requirements Memorandum to SECY-06-0220 - Final Rule to Update 10 CFR Part 52, "Licenses, Certifications, and Approvals for Nuclear Power Plants" April 11, 2007.

Appendix A–JUSTIFICATION FOR CHANGES TO THE GENERIC DCD

This LTR examines proposed changes pertaining to DCD Tier 2 design material. This LTR demonstrates that the proposed changes meet the requirements for NRC approval of a design certification amendment per the proposed revision to 10 CFR 52.63(a).

10 CFR 52.63(a)(1)(vi) (as proposed in SECY-06-220) allows for a change to a generic DCD if the change "Contributes to increased standardization of the certification information." As discussed below, the proposed changes to the generic DCD satisfy this criterion.

The proposed changes involving the plant MV electrical system are intended to be generic and applicable to all COL applicants that reference the ABWR design certification. In particular, the proposed design configuration changes for a dual MV electrical system design allow greater flexibility in equipment procurement without any negative effect on design basis assumptions. Performance characteristics of the alternate MV electrical system meet or exceed current DCD descriptions of their intended functions. Alternate TS requirements appropriate for a dual MV electrical system are proposed. DCD Tier 1 requirements are not affected by the proposed changes.

The MV electrical system specified in the DCD could not have been built with standard product line switchgear or standard product line protection schemes and still meet the requirements for voltage regulation and fault current interruption. Therefore, absent a design certification amendment to provide for a dual voltage system, plant-specific departures will be inevitable, which would likely result in decreased standardization. The proposed revision to the DCD will follow current design practice and regulatory requirements similar to existing analyzed international design, and therefore will result in increased standardization relative to the existing DCD.

At least one prospective COL applicant (i.e., the COL applicant for STP Units 3 and 4) intends to implement the proposed departures from the ABWR DCD. Furthermore, it may be expected that other COL applicants will also desire to implement the proposed departures.

Given the generic nature of these proposed changes and the fact that at least one COL applicant intends to make the changes, it would contribute to increased standardization if the NRC were to make a generic change to the DCD to incorporate these proposed changes. Therefore, the proposed changes satisfy the criteria in 10 CFR 52.63(a)(1).

Appendix B - ABWR DCD/TIER 2 & TS MARKED CHANGES

- FIGURE-1: DCD FIGURE 8.3-1 (SHEET 1 OF 3)
- FIGURE-2: PROPOSED FIGURE 8.3-1 (SHEET 1 OF 3) ABWR ELECTRICAL SYSTEM
- ABWR DCD TIER 2 MARKED CHANGES
- ABWR TECHNICAL SPECIFICATIONS MARKED CHANGES

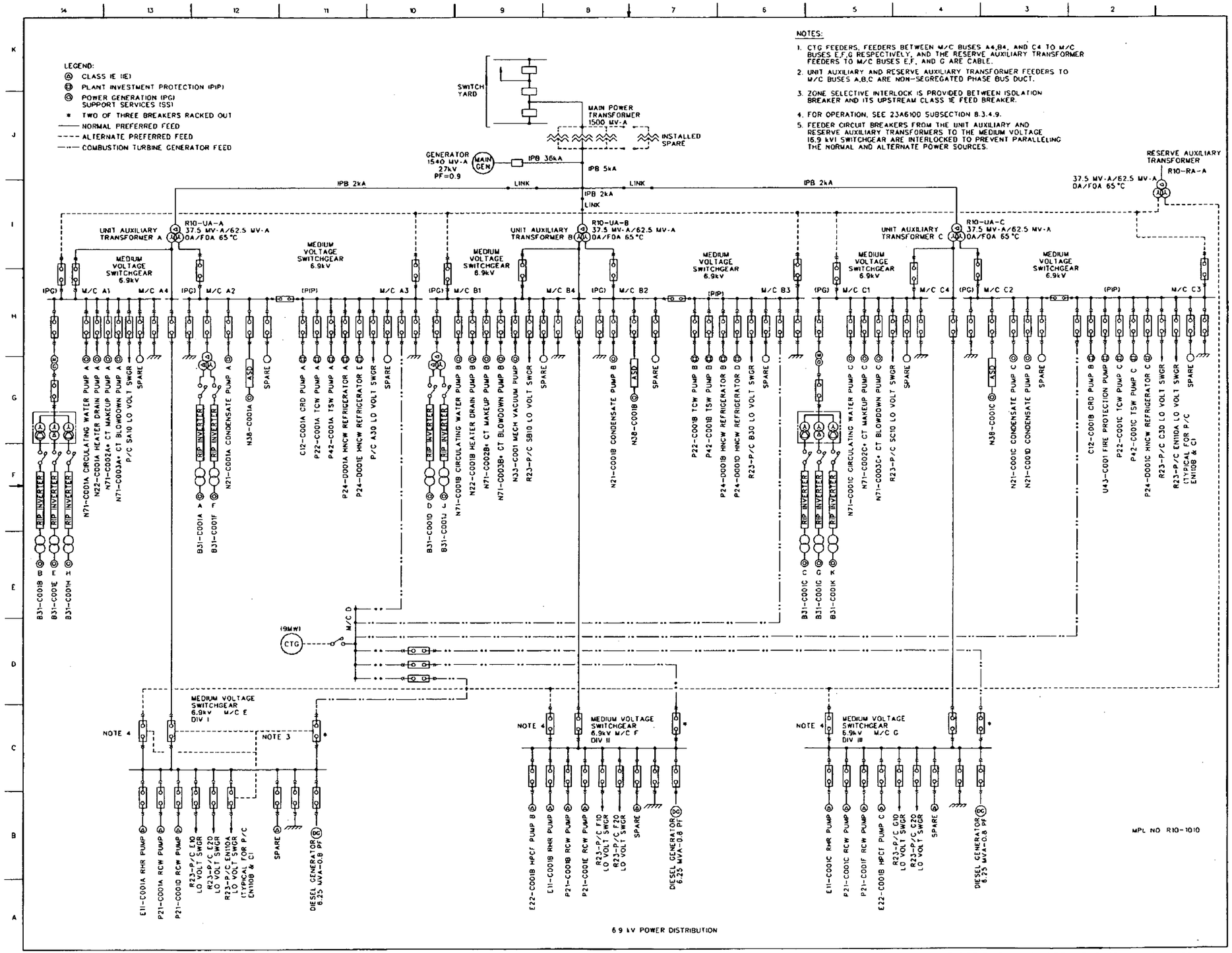
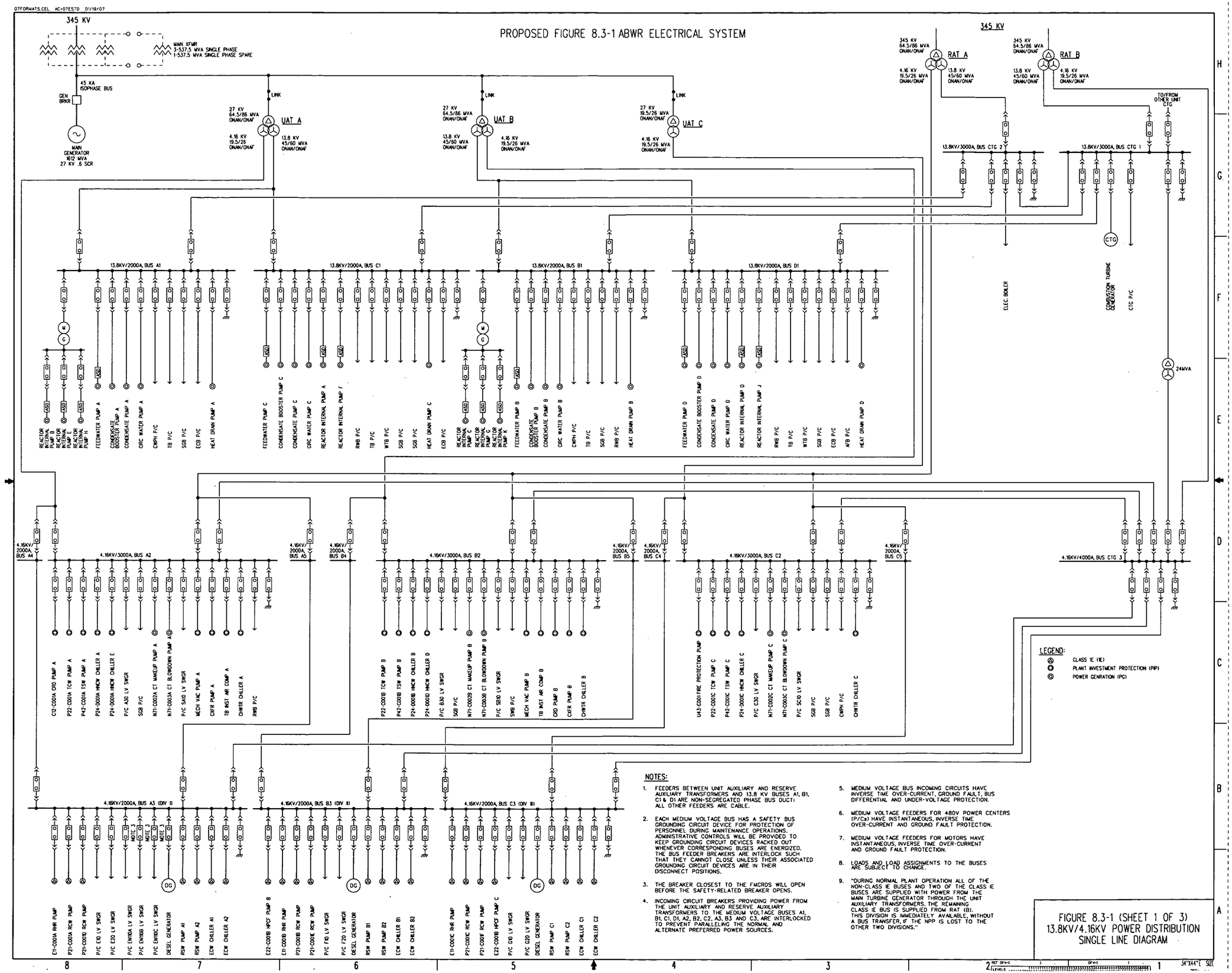


FIGURE 8.3-1 ELECTRICAL POWER DISTRIBUTION SYSTEM SLD (Sheet 1 of 3)



NOTES:

1. FEEDERS BETWEEN UNIT AUXILIARY AND RESERVE AUXILIARY TRANSFORMERS AND 13.8 KV BUSES A1, B1, C1 & D1 ARE NON-SEGREGATED PHASE BUS DUCT; ALL OTHER FEEDERS ARE CABLE.
2. EACH MEDIUM VOLTAGE BUS HAS A SAFETY BUS GROUNDING CIRCUIT DEVICE FOR PROTECTION OF PERSONNEL DURING MAINTENANCE OPERATIONS. ADMINISTRATIVE CONTROLS WILL BE PROVIDED TO KEEP GROUNDING CIRCUIT DEVICES RACKED OUT WHENEVER CORRESPONDING BUSES ARE ENERGIZED. THE BUS FEEDER BREAKERS ARE INTERLOCK SUCH THAT THEY CANNOT CLOSE UNLESS THEIR ASSOCIATED GROUNDING CIRCUIT DEVICES ARE IN THEIR DISCONNECT POSITIONS.
3. THE BREAKER CLOSEST TO THE FMCRDS WILL OPEN BEFORE THE SAFETY-RELATED BREAKER OPENS.
4. INCOMING CIRCUIT BREAKERS PROVIDING POWER FROM THE UNIT AUXILIARY AND RESERVE AUXILIARY TRANSFORMERS TO THE MEDIUM VOLTAGE BUSES A1, B1, C1, D1, A2, B2, C2, A3, B3 AND C3, ARE INTERLOCKED TO PREVENT PARALLELING THE NORMAL AND ALTERNATE PREFERRED POWER SOURCES.
5. MEDIUM VOLTAGE BUS INCOMING CIRCUITS HAVE INVERSE TIME OVER-CURRENT, GROUND FAULT, BUS DIFFERENTIAL AND UNDER-VOLTAGE PROTECTION.
6. MEDIUM VOLTAGE FEEDERS FOR 480V POWER CENTERS (P/Cs) HAVE INSTANTANEOUS, INVERSE TIME OVER-CURRENT AND GROUND FAULT PROTECTION.
7. MEDIUM VOLTAGE FEEDERS FOR MOTORS HAVE INSTANTANEOUS, INVERSE TIME OVER-CURRENT AND GROUND FAULT PROTECTION.
8. LOADS AND LOAD ASSIGNMENTS TO THE BUSES ARE SUBJECT TO CHANGE.
9. "DURING NORMAL PLANT OPERATION ALL OF THE NON-CLASS 1E BUSES AND TWO OF THE CLASS 1E BUSES ARE SUPPLIED WITH POWER FROM THE MAIN TURBINE GENERATOR THROUGH THE UNIT AUXILIARY TRANSFORMERS. THE REMAINING CLASS 1E BUS IS SUPPLIED FROM RAT (B). THIS DIVISION IS IMMEDIATELY AVAILABLE, WITHOUT A BUS TRANSFER, IF THE NPP IS LOST TO THE OTHER TWO DIVISIONS."

FIGURE 8.3-1 (SHEET 1 OF 3)
13.8KV/4.16KV POWER DISTRIBUTION
SINGLE LINE DIAGRAM

1.2.2.13.2 Unit Auxiliary ~~Transformer~~ Transformers

The unit auxiliary AC power system and/or offsite power supplies power to unit loads that are non-safety-related and uses the main generator as the normal power source with the reserve auxiliary ~~transformer~~ transformers as ~~a~~ backup ~~source~~ sources. The unit auxiliary transformer steps down the AC power to the ~~6900V~~ 13.8 kV and 4.16 kV station bus ~~voltage.~~ voltages.

1.2.2.13.3 Isolated Phase Bus

The isolated phase bus duct system provides electrical interconnection from the main generator output terminals to the generator breaker and from the generator breaker to the low voltage terminals of the main transformer, and the high voltage terminals of the unit auxiliary transformers. During the time the main generator is off line, the generator breaker is open and power is fed to the unit auxiliary transformers by backfeeding from the main transformer. During startup, the generator breaker is closed ~~at about 7%~~ between 10% and 15% power to provide power to the main and the unit auxiliary transformers for normal operation of the plant.

A package cooling unit is supplied with the isolated bus duct system.

1.2.2.13.4 Non-Segregated Phase Bus and Cable Bus

The non-segregated phase bus or cable bus provides the electrical interconnection between the unit auxiliary transformers and their associated ~~6.9 kV metal clad switchgear.~~ medium-voltage switchgear, and between the reserve auxiliary transformers and their associated medium-voltage switchgear.

1.2.2.13.5 Metal-clad Switchgear

The metal-clad switchgear distributes the ~~6.9 kV~~ 13.8 kV and 4.16 kV power. Circuit breakers are drawout type, stored energy vacuum breakers. The switchgear interrupting rating shall be determined in accordance with requirements of ANSI ~~C37.10~~. C37.010

1.2.2.13.6 Power Center

The power center is summarized in Subsection 8.3.1.1.2.1.

1.2.2.13.7 Motor Control Center

The motor control center is summarized in Subsection 8.3.1.1.2.2.

1.2.2.13.8 Raceway System

The Raceway System is a plant-wide network comprised of metallic cable trays, metallic conduits and supports. Raceways are classified for carrying medium voltage power cables, low voltage power cables, control cables and low level signal/instrumentation cables. Divisional cables are routed in separate cable raceways for each division.

Fiber optic dataways are not restricted to raceway classifications, but would generally be run with control cables due to their common destinations.

1.2.2.13.9 Grounding Wire

Station grounding and surge protection are discussed in Section 8A.1.

1.2.2.13.10 Electrical Wiring Penetration

Electrical wiring penetrations are described in Subsection 8.3.3.6.1.2 (7).

1.2.2.13.11 Combustion Turbine Generator

The primary function of the Combustion Turbine Generator (CTG) is to act as a standby onsite non-safety power source to feed Plant Investment Protection (PIP) non-safety loads during Loss of Preferred Power (LOPP) events.

The unit also provides an alternate AC power source in case of a station blackout event, as defined by Appendix B of Regulatory Guide 1.155 (Appendix 1C).

1.2.2.13.12 Direct Current Power Supply

The plant has four independent Class 1E and three non-Class 1E 125 VDC power systems.

1.2.2.13.12.1 Unit Auxiliary DC Power System

The Unit Auxiliary DC Power System supplies power to unit DC loads that are non-safety-related. The system consists of three battery chargers, three batteries, and three distribution panels.

1.2.2.13.12.2 Unit Class 1E DC Power System

The Unit Class 1E DC Power System supplies 125 VDC power to the unit Class 1E loads. Battery chargers are the primary power sources. The system, which includes storage batteries that serve as standby power sources, is divided into four divisions, each with its own independent distribution network, battery, and charger.

1.2.2.13.13 Emergency Diesel Generator System

The Emergency Diesel Generator System is supplied by three diesel generators. Each Class 1E division is supplied by a separate diesel generator. There are no provisions for ~~transferring Class 1E buses~~ automatic transfer of Class 1E buses between standby AC power supplies or supplying more than one division of engineered safety feature (ESF) from one diesel generator. This one-to-one relationship ensures that a failure of one diesel generator can affect only one ESF division. The diesel generators are housed in the Reactor Building which is a Seismic Category I structure, to comply with applicable NRC and IEEE design guides and criteria.

1.2.2.13.14 Vital AC Power Supply

1.2.2.13.14.1 Safety System Logic and Control Power System

Four divisions of the Safety System Logic and Control (SSLC) Power System provide an uninterruptible Class 1E source of 120-VAC single-phase control power. The primary power source for the SSLC Power System is the Class 1E AC power system. On loss of AC power, the appropriate divisional battery immediately assumes load without interruption. When AC power is restored, it resumes the load without interruption.

1.2.2.13.14.2 Uninterruptible Power System

The Uninterruptible Power System (UPS) supplies regulated 120 VAC single-phase power to non-Class 1E instrument and control loads which require an uninterruptible source of power. The power sources for the UPS are similar to those for the SSLC, but are non-Class 1E.

1.2.2.13.14.3 Reactor Protection System Alternate Current Power Supply

The Reactor Protection System alternate current power supply is described in Subsection 8.3.1.1.4.2.1.

1.2.2.13.15 Instrument and Control Power Supply

The instrument and control (I&C) power supply provides 120 VAC single-phase power to I&C loads which do not require an uninterruptible power source.

1.2.2.13.16 Communication System

The communication system is summarized in Subsection 9.5.2.

1.2.2.13.17 Lighting and Servicing Power Supply

non-Class 1E plant investment protection (PIP) buses, which are backed up by the combustion turbine generator.

The design basis for the lighting facilities is the standard for the Illuminating Engineering Society. Special attention is given to areas where proper lighting is imperative during normal and emergency operations. The system design precludes the use of mercury vapor fixtures in the containment and the fuel handling areas. The normal lighting systems are fed from the ~~unit auxiliary transformers.~~ Emergency power is supplied by engineered safety buses backed-up by diesel generators. Normal operation and regular simulated offsite power loss tests verify system integrity.

1.2.2.14 Power Transmission Systems

1.2.2.14.1 Reserve Auxiliary ~~Transformer~~ Transformers

~~The reserve auxiliary transformer provides the alternate preferred feed for the Class 1E buses M/C, E, F, and G. It also provides an alternate feed to non-Class 1E 6.9 kV buses.~~

Each reserve auxiliary transformer provides alternate preferred feeds to two power generation buses and can feed any of the three plant investment protection buses and any of the three Class 1E 4.16 kV buses.

- Safe Shutdown (SSD)

  "Safe shutdown (non-design basis accident (non-DBA)) for station blackout means bringing the plant to those shutdown conditions specified in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate..."

1C.2.2 Plant SBO Design Basis

1C.2.2.1 General SBO Design Basis

- The ABWR design will mitigate station blackout events as defined in Subsection 1C.2.2.
- The ABWR design will comply with 10CFR50.63 requirements relative to the loss of all alternating current power sources.
- The ABWR design will include and utilize an Alternate AC (AAC) power source to comply with 10CFR50.63 requirements and the recommendations for ALWRs, as defined by the NRC in SECY 90-016.
- The ABWR design will be consistent with Regulatory Guide 1.155 and NUMARC 87-00 guidelines relative to an AAC power source.
- The ABWR design AAC power source will supplement and compliment the current offsite AC power connections, the onsite normal AC power sources (the unit auxiliary and reserve auxiliary transformers), the onsite emergency AC power sources (DGs) and the onsite DC power sources.

1C.2.2.2 Specific SBO Design Basis

- The ABWR AAC power source will be a combustion turbine generator (CTG).
- The normal design function of the CTG will be to act as a standby, non-safety-related power source for the plant investment protection (PIP) non-safety-related loads during loss of preferred power (LOPP) events.
- The CTG will be capable of being manually configured to provide power to a selected safety-related emergency bus within 10 minutes during SBO events.
- The CTG will automatically start, accelerate to required speed, reach required voltage and frequency and be ready to accept PIP loads ~~within two~~ in less than ten minutes of the receipt of its start signal.
- The CTG will be a diverse, self contained unit (including its auxiliaries) and will be independent of the plant preferred and emergency power sources.

- CTG power will be used to restore various selected plant environmental control components (HVAC, chillers, etc.) as soon as possible.
- The CTG will not normally be used to provide power connected to the plant loads.
- The CTG will be capable of being inspected, tested, and maintained.
- The CTG capabilities will be demonstrated prior to shipment, during initial pre-operational test, and periodically during power operation.
- Required plant core cooling and containment integrity during the SBO duration (10 minutes) will not depend on any AC power sources.

1C.2.3 Plant SBO Safety Analysis

1C.2.3.1 Plant Event Evaluations

1C.2.3.1.1 Plant Normal Operation

The normal configuration of the onsite AC power distribution system and its individual power sources are described in Subsections 8.2.1 and 8.3.1. The CTG (AAC) system attributes and its interconnections are described in Subsection 9.5.11 and in Subsection 8.3.1, respectively. Both are shown on Figure 8.3-1.

The normal and alternate preferred AC power sources supply safety-related and non-safety-related loads. Power to these loads are supplied from the unit auxiliary transformers (UATs) units and the reserve auxiliary ~~transformer (RAT).~~ transformers (RATs).

The CTG is designed to supply standby power to the non-Class 1E ~~6.9~~ 4.16 kV buses which carry the plant investment protection (PIP) loads. The CTG automatically starts on detection of under voltage on the PIP buses. When the CTG is ready to assume load, if the voltage is still deficient, power automatically transfers to the CTG (refer to Figure 8.3-1).

The CTG can also supply standby power to the non-Class 1E ~~6.9~~ 13.8 kV power generation buses which supply ~~feedwater and~~ condensate pumps. ~~These buses normally receive power from the unit auxiliary transformers and supply power to the plant investment protection (PIP) buses through a cross tie. The cross tie automatically opens on loss of power but may be manually reclosed if it is desired to operate a condensate pump from the combustion turbine generator or the reserve auxiliary transformer which are connectable to the PIP buses.~~ This arrangement allows the powering of load groups of non-Class 1E equipment in addition to the Class 1E divisions which may be used to supply water to the reactor vessel (refer to Figure 8.3-1).

These buses normally receive power from the unit auxiliary transformers. Breakers on the CTG bus and power generation buses may be manually closed if it is desired to operate a condensate pump from the combustion turbine generator or the reserve auxiliary transformer.

1C.2.3.1.2 LOPP Events

The ABWR onsite emergency power sources during LOPP events are the diesel generator (DG) units. These units and their system responses are discussed in Subsection 8.3.1.1.8. However, the CTG is available to provide backup emergency power during LOPP to safety-related loads by manual reconfiguration of the CTG and the loads.

1C.2.3.1.3 SBO Events

The CTG is the AC power source during an SBO event. The CTG can supply ~~6.9~~ 4.16 kV Class 1E buses through the realignment of pre-selected breakers during SBO events. The CTG will reach operational speed and voltage in ~~2~~ less than 10 minutes and will be available for bus connection within 10 minutes. Upon a LOPP, the CTG is automatically started and configured to non-safety-related PIP loads. Plant operators using appropriate procedures will reconfigure any of the ~~6.9~~ 4.16 kV Class 1E buses to accept CTG power. Refer to Tier 2 Subsections 8.3.1.1.7 and 9.5.11.

1C.2.3.1.4 Other Operational Capabilities

The CTG can be used for postulated prolonged SBO scenarios.

Up to the limits of its capacity, the CTG can be connected to any combination of Class 1E and non-Class 1E buses to supply loads in excess of the minimum required for safe shutdown.

The ABWR design provides for local and main control room operation of the CTG. Communication is available between the CTG area and the main control room.

1C.2.3.2 Alternative AC Power Source Evaluation

The alternate AC power source (1) is a combustion turbine generator, (2) is provided with an immediate fuel supply that is separate from the fuel supply for other onsite emergency AC power systems, (3) fuel will be sampled and analyzed consistent with applicable standards, (4) is capable of operating during and after a station blackout without any AC support systems powered from the preferred power supply or the blacked-out units Class 1E power sources (5) is designed to power all of the PIP and/or Class 1E shutdown loads necessary within 10 minutes of the onset of the station blackout, such that the plant is capable of maintaining core cooling and containment integrity (6) will be protected from design basis weather events (except seismic and tornado missiles) to the extend that there will be no common mode failures between offsite preferred sources and the combustion turbine generator power source, (7) will be subject to quality assurance guidelines commensurate with its importance to SBO, (8) will have sufficient capacity and capability to supply ~~one division~~ two divisions of Class 1E loads, (9) will have sufficient capacity and capability to supply the required non-Class 1E loads

used for a safe shutdown, (10) will undergo factory testing to demonstrate its ability to reliably start, accelerate to required speed and voltage and supply power ~~within two~~ in less than ten minutes, (11) will not normally supply power to nuclear safety-related equipment except under specific conditions, (12) will not be a single point single failure detriment to onsite emergency AC power sources, and (13) will be subject to site acceptance testing; periodic preventative maintenance, inspection, testing; operational reliability assurance program goals.

Based on the above, the ABWR design for the AAC power supply complies with 10CFR50.63, with Regulatory Guide 1.155 and with NUMARC 87-00 and meets the SBO rule.

1C.2.4 Plant Conformance With SBO Requirements

A brief review of the general ABWR design conformance with various SBO requirements and guidelines is given below. A more complete in-depth and specific review of each of the SBO regulatory requirements or guidelines is given in the enclosed tables (refer to Tables 1C-1 through 1C-3).

1C.2.4.1 10CFR50.63 Requirements

The ABWR complies with the 10CFR50.63 requirements. Special attention was given to the regulation definition of the SBO event, the event conditions, and the requirement for safe shutdown status. The ABWR utilizes the AAC power source option and provides an evaluation of the requirements/compliances in Table 1C-1.

1C.2.4.2 New ALWR Requirements (SECY 90-016)

A review of the new ALWR SBO requirements in SECY 90-016 recommendations was conducted. The ABWR design is in compliance with the ALWR recommendations.

1C.2.4.3 Regulatory Guide 1.155 Guideline Requirements

A review of the ABWR CTG design relative to Sections 3.3.5, 3.3.6, 3.3.7, 3.4 and Appendix A and B of RG 1.155 was conducted. CTG design fully complies with the cited requirements. The use of the CTG as an AAC power source in the ABWR design eliminates the need for a SBO coping analyses by limiting the SBO duration to 10 minutes or less. No operator action is required within the initial ten minutes (refer to Table 1C-2).

1C.2.4.4 NUMARC 87-00 Guidelines

A review of the ABWR CTG design relative to the NUMARC SBO guidelines, Subsections 7.1.1 and 7.1.2 and Appendices A and B was conducted. The ABWR design with CTG is consistent with the NUMARC guidelines (refer to Table 1C-3).

Table 1C-1 ABWR Design Compliance with 10CFR50.63 Regulations

Requirements	Compliance
§ 10CFR50-63 Loss of all alternating current power.	
§ 50.63 Loss of all alternating current power.	
(a) Requirements	
(1) Each light-water-cooled nuclear power plant licensed to operate must be able to withstand for a specified duration and recover from a station blackout as defined in § 50.2. The specified station blackout duration shall be based on the following factors:	The ABWR design will utilize an alternate AC (AAC) power source to mitigate and recover from station blackout events (defined in 50.2). The AAC power source will be a combustion turbine generator (CTG). The CTG will be totally independent from offsite preferred and onsite Class 1E sources. A ten (10) minute interval is used as the ABWR design basis for the SBO event duration. The AAC power source provides a diverse power source to the plant.
(i) The redundancy of the onsite emergency AC power sources	The ABWR design CTG will have sufficient capacity and capabilities to power the necessary reactor core coolant, control and protective systems including station battery and other auxiliary support loads needed to bring the plant to a safe and orderly shutdown condition (defined in 50.2). The CTG supplied will be rated at ~~a minimum of 9~~ least 20 MWe and be capable of accepting shutdown loads within 10 minutes. The current plant onsite emergency power sources include three (3) independent and redundant DG divisions which are designed to supply approximately ~~5~~ 7.2 MWe within 1 minute. Additionally, the plant has been designed to accommodate AC power source losses for a period up to 8 hours. The AAC limits the SBO event to 10 minutes.
(ii) The reliability of the onsite emergency AC power sources	The current onsite emergency AC power sources will have the following reliability: DGs...0.975 The CTG will have the following reliability: CTG...0.95 The above values are used in the ABWR-PRA analysis.

Table 1C-1 ABWR Design Compliance with 10CFR50.63 Regulations (Continued)

Requirements	Compliance
(b) Limitation of scope (c) Implementation (1) Information Submittal. For each light-water-cooled nuclear power plant licensed to operate after the effective date of this amendment, the licensee shall submit the information defined below to the Director by 270 days after the date of license issuance. (i) A proposed station blackout duration to be used in determining compliance with paragraph (a) of this section, including a justification for the selection based on the four factors identified in paragraph (a) of this section in less than 10	In addition to the discussion under (a) above, the following is noted. The ABWR design SBO duration time considerations are consistent with RG1.155 and NUMARC-87-00. Upon loss of offsite power (LOPP) and upon the subsequent loss of all on site AC emergency power sources (three independent and redundant DGs), the CTG can be manually connected to any one of the three safety-related (Class 1E) ~~busses~~ buses by closing two circuit breakers. The alternative AC (AC) power source will automatically start, and ~~within 2~~ in less than 10 minutes be up to required speed and voltage. It will then automatically connect to selected PIP buses (non-Class 1E) loads. During the first 10 minutes, the reactor will have automatically tripped, the main steam isolation valves (MSIVs) closed, and the RCIC actuated. The RCIC system will automatically control reactor coolant level. Any necessary relief valve operation will also be automatic. Within the 10 minute SBO interval, none of the above actions will require AC power or manual operator actions. The reconfiguration of the CTG to pick up the Class 1E buses will require manual closure of two circuit breakers from the control room. Upon restoration of power to the safety bus(es), the remaining safe shutdown loads will be energized.
(ii) A description of the procedures that will be implemented for station blackout events for the duration determined in paragraph (c)(1)(i) of this section and for recovery therefrom	Appropriate plant procedures will be developed by the COL applicant for the ABWR design. These procedures be integrated/coordinated with the plant EOPs, using the EOP methodology. Procedures will consider instructions for operator actions, responses, timing, and related matters during the SBO event.

Table 1C-1 ABWR Design Compliance with 10CFR50.63 Regulations (Continued)

Requirements	Compliance
(iii) A list of modifications to equipment and associated procedures, if any, necessary to meet the requirements of paragraph (a) of this section, for the specified station blackout duration determined in paragraph (c)(1)(i) of this section, and a proposed schedule for implementing the stated modifications	Modifications to equipment and procedures is not applicable since the use of an AAC source and other SBO considerations are included in the ABWR design.
(2) Alternate AC source: The alternate AC power source(s), as defined in § 50.2, will constitute acceptable capability to withstand station blackout provided an analysis is performed which demonstrates that the plant has this capability from onset of the station blackout until the alternate AC source(s) and required shutdown equipment are started and lined up to operate. The time required for startup and alignment of the alternate AC power source(s) and this equipment shall be demonstrated by test. Alternate AC source(s) serving a multiple unit site where onsite emergency AC source are not shared between units must have, as a minimum, the capacity and capability for coping with a station blackout in any of the units. At sites where onsite emergency AC sources are shared between units, the alternate AC source(s) must have the capacity and capability as required to ensure that all units can be brought to and maintained in safe shutdown (non-DBA) as defined in § 50.2. If the alternate AC source(s) meets the above requirements and can be demonstrated by test to be available to power the shutdown buses within 10 minutes of the onset of station blackout, then no coping analysis is required.	The ABWR CTG will be automatically initiated upon the loss of power to the PIP buses. The CTG will achieve required speed and voltage ~~within 2~~ in less than 10 minutes. The CTG will be manually connected to safe shutdown buses within 10 minutes. These equipment capabilities will be demonstrated 1) by the manufacturer's component tests, 2) by the CTG initial startup tests and 3) periodically by the COL applicant as part of his operational reliability assurance program. The ABWR design is a single unit plant arrangement design. The CTG AAC source is available to power shutdown loads within 10 minutes as described above. Therefore, no coping analysis is required. In addition, the ABWR is designed with an 8-hour battery to accommodate station blackout without the need for AC power. Also, the three independent emergency diesel generator systems will accommodate one DG out of service, plus a single failure, with the remaining DG capable of bringing the plant to safe shutdown.
(3) Regulatory Assessment:	
(4) Implementation Schedule: (53 FR 23215, June 21, 1988)	

Table 1C-2 ABWR Design Compliance with Regulatory Guide 1.155

Requirements	Compliance
Regulatory Guide 1.155—Station Blackout	
Regulatory Position	
3.3.5 If an AAC power source is selected specifically for satisfying the requirements for station blackout, the design should meet the following criteria:	The ABWR AAC power source is not normally connected to the preferred or the onsite emergency AC power system. Two open circuit breakers—one Class 1E and the other non-Class 1E—separate the CTG from the safety-related emergency buses.
1. The AAC power source should not normally be directly connected to the preferred or the blacked-out unit's onsite emergency AC power system.	The AAC power source is also not normally connected to any of the preferred AC power sources or their associated non-safety-related buses. ~~A non-Class 1E circuit breaker separates the CTG from the PIP buses.~~
2. There should be a minimum potential for common cause failure with the preferred or the blacked-out unit's onsite emergency AC power sources. No single-point vulnerability should exist whereby a weather-related event or single active failure could disable any portion of the blacked-out unit's onsite emergency AC power sources or the preferred power sources and simultaneously fail the AAC power source.	The ABWR design minimizes the potential for a) common cause failures between the preferred sources and the onsite emergency power sources; b) common cause failures between onsite emergency power sources themselves; c) common cause failures between onsite power sources and the AAC power source; and d) common cause failures between preferred sources and the AAC power source. The design also precludes interactions between preferred, onsite emergency, and AAC power systems resulting from weather related events or single failures such that a single point vulnerability will not simultaneously fail both the AAC power source and the onsite emergency or offsite preferred power source(s). This is accomplished by having onsite emergency and the AAC power sources inside weather protected buildings and by maintaining adequate separation between the four power sources. None of the four standby power sources share emergency buses or loads, auxiliary services or instrumentation and controls prior to the recovery actions from the SBO event. These power sources are physically, electrically, mechanically and environmentally separated.

A non-Class 1E circuit breaker separates the CTG from the power generation bus via a normally open 13.8 kV breaker.

Table 1C-2 ABWR Design Compliance with Regulatory Guide 1.155 (Continued)

Requirements	Compliance
3. The AAC power source should be available in a timely manner after the onset of station blackout and have provisions to be manually connected to one or all of the redundant safety buses as required. The time required for making this equipment available should not be more than 1 hour as demonstrated by test. If the AAC power source can be demonstrated by test to be available to power the shutdown buses within 10 minutes of the onset of station blackout, no coping analysis is required.	The ABWR AAC design power source will be automatically started and reach rated speed and voltage and be available to supply PIP loads ~~within 2~~ in less than 10 minutes, and safety-related loads within 10 minutes for any loss of preferred offsite power sources (LOPP). The design has provisions to assure the timely manual interconnection between the AAC (CTG) and any one or more of the safety-related shutdown buses. The ABWR AAC design will be demonstrated by test to show that it can be connected to safety-related buses within 10 minutes. Therefore, no coping analysis is required.
4. The AAC power source should have sufficient capacity to operate the systems necessary for coping with a station blackout for the time required to bring and maintain the plant in safe shutdown.	The ABWR AAC power source is rated at ~~9~~ least 20 MWe, which is more than sufficient capacity to operate the necessary safe shutdown loads which are less than ~~5~~ 7.2 MWe.
5. The AAC power system should be inspected, maintained, and tested periodically to demonstrate operability and reliability. The reliability of the AAC power system should meet or exceed 95% as determined in accordance with NSAC-108 (Reference 11) or equivalent methodology.	The ABWR design includes previsions to demonstrate the operability and reliability of the AAC power source. The CTG will be subject to surveillance inspection, testing and maintenance in accordance with the manufacturer's requirements, the COL applicant's maintenance program and with operational reliability assurance program requirements. The CTG will meet or exceed a reliability goal of 0.95 in accordance with NSAC-108 or equivalent methodology.

Table 1C-2 ABWR Design Compliance with RG 1.155 (Continued)

Requirements		Compliance
Appendix B—Guidance Regarding Systems/Components		
	Alternate AC Sources	**ABWR AAC Power Source**
Safety-Related Equipment (Compliance with IEEE-279)	Not required, but the existing Class 1E electrical systems must continue to meet all applicable safety-related criteria.	Existing onsite emergency power sources, buses and loads will continue to meet all applicable safety-related criteria.
Redundancy	Not required.	—
Diversity from Existing EDGs	See Regulatory Position 3.3.4 of this guide.	The ABWR design will utilize a AAC diverse power source from that of the EDGs. A qualified combustion turbine generator will be used as the AAC.
Independence from Existing Safety-Related Systems	Required if connected to Class 1E buses. Separation to be provided by 2 circuit breakers in series (1 Class 1E at the Class 1E bus and 1 non-Class 1E).	~~Two~~ At least two breakers separate the onsite emergency power buses from the CTG. One breaker is Class 1E and the breaker closest to the CTG is non-Class 1E (see Figure 8.3-1).
Seismic Qualification	Not required.	—
Environmental Consideration	If normal cooling is lost, needed for station blackout event only and not for design basis accident (DBA) conditions. Procedures should be in place to affect the actions necessary to maintain acceptable environmental conditions for the required equipment. See Regulatory Position 3.2.4.	The use of the ACC power source will assure that the plant equipment/environment cooling loss will be limited to 10 to 60 minutes (SBO duration). Normal plant cooling loads will be restored after shutdown loads are reestablished. Temperature rise conditions will be limited to minutes rather than hours
Capacity	Specified in § 50.63 and Regulatory Position 3.3.4.	The AAC power source is capable of powering more than the minimum required shutdown loads.
Quality Assurance	Indicated in Regulatory Position 3.5.	The ABWR design will be subjected to the quality assurance standards cited in Appendix A.

Table 1C-3 ABWR Design Compliance with NUMARC 87-00 Guidelines (Continued)

Requirements	Compliance
Appendix A — Definitions	
This appendix defines the terminology used throughout the guide.	The ABWR AAC power source design will meet the following requirements:
ALTERNATE AC POWER SOURCE. An alternating current (AC) power source that is available to and located at or nearby a nuclear power plant and meets the following requirements: (i) Is connectable to but not normally connected to the preferred or onsite emergency AC power systems (ii) Has minimal potential for common cause failure with offsite power or the onsite AC power sources (iii) Is available in a timely manner after the onset of station blackout (iv) Has sufficient capacity and reliability for operation of all systems necessary for coping with a station blackout and for the time required to bring and maintain the plant in safe shutdown (Hot Shutdown or Hot Standby, as appropriate) (v) Is inspected, maintained, and tested periodically to demonstrate operability and reliability as set forth in Appendix B	(i) The design is connectable to (but not normally connected to) the preferred or onsite emergency AC power sources. Two normally open breakers separate the AAC CTG from the safety-related onsite emergency power buses. ~~A single~~ normally open ~~breaker~~ separate~~s~~ the AAC CTG from the non-safety-related PIP buses (preferred power) (see Figure 8.3-1). (ii) The ABWR design has a minimal potential for common cause failure between preferred power or onsite AC power sources. The ABWR AAC power source is a diverse power supply to the normal onsite emergency DGs. The AAC power supply is totally independent of the preferred and onsite power sources. The AAC power source automatically starts and is available for loading in ~~two~~ minutes. The AAC power supply is connectable to a Class 1E bus through the actuation of two (2) manual operated circuit breakers. The AAC power source is normally electrically, physically, mechanically, and environmentally isolated from the preferred and onsite power sources. The AAC power source is normally used during LOPP and SBO events. However, the CTG can be used for a number of operational services (e.g. maintenance backup, etc.). (iii) The ABWR AAC power source is available in a timely manner after the onset of a SBO event. The AAC power source automatically starts on LOPP, attains required speed and voltage ~~within two (2)~~ minutes, and is capable of being connected to shutdown loads within ten (10) minutes.

Non-Class 1E

breakers

less than 10

in less than ten (10)

Table 1C-3 ABWR Design Compliance with NUMARC 87-00 Guidelines (Continued)

Requirements	Compliance 7.2 20
	(iv) The ABWR AAC power source is rated a minimum of ~~9~~ MWe. The shutdown loads are less than ~~5~~ MWe. The CTG reliability is 0.95. The ABWR is expected to be in hot shutdown condition in twenty four (24) hours, and in cold shutdown condition in ninety-six (96) hours. The CTG, is designed to run indefinitely under SBO conditions at rated load. A seven-day fuel supply is available on the site for the CTG.
	(v) The ABWR AAC power source will be capable of being inspected, maintained and tested periodically to demonstrate its operability and reliability to guidelines set forth in Appendix B.
REQUIRED COPING DURATION. The time between the onset of station blackout and the restoration of offsite AC power to safe shutdown buses.	The ABWR AAC power source design does not require a formal SBO coping analysis. The AAC power source will be available to supply shutdown loads within ten (10) minutes. The current design requirements associated with DBA events assure that the plant will be able to cope with a ten (10) minute SBO event.
SAFE SHUTDOWN. For the purpose of this procedure safe shutdown is the plant conditions defined in plant technical specifications as Hot Standby or Hot Shutdown, as appropriate.	The ABWR design will assure safe shutdown plant conditions as defined by the Plant Technical Specifications and the definition in 10CFR50.63.
STATION BLACKOUT. Means the complete loss of alternating current (AC) electric power to the essential and nonessential switchgear buses in a nuclear power plant (i.e., loss of offsite electric power system concurrent with turbine trip and unavailability of onsite emergency AC power system). Station Blackout does not include the loss of available AC power to buses fed by station batteries through inverters or by Alternate AC power sources as defined in this appendix, nor does it assume a concurrent single failure or a design basis accident. At a multi-unit site, station blackout is assumed to occur in only one unit unless the emergency AC power sources are totally shared between the units.	The ABWR design accommodates the SBO definition and the other definitions defined in 10CFR50.63. The ABWR design utilizes the current available station batteries throughout the event. The station batteries will be recharged as necessary by the AAC power source.

Table 1C-3 ABWR Design Compliance with NUMARC 87-00 Guidelines (Continued)

Requirements	Compliance
B.4 Physical separation of AAC components from safety-related components or equipment shall conform with the separation criteria applicable for the unit's licensing basis.	The ABWR AAC power source design maintains physical separation between safety-related components or equipment and the CTG by adhering to applicable separation criteria used in the plant licensing basis.
Connectability to AC Power Systems	
B.5 Failure of AAC components shall not adversely affect Class 1E AC power systems.	The ABWR AAC power source design and its associated components failures will not adversely affect Class 1E AC power systems. Class 1E AC power system failures will not affect AAC power source operability.
B.6 Electrical isolation of AAC power shall be provided through an appropriate isolation device. If the AAC source is connected to Class 1E buses, isolation shall be provided by two circuit breakers in series (one Class 1E breaker at the Class 1E bus and one non-Class 1E breaker to protect the source).	The ABWR AAC power source is electrically isolated from the Class 1E power sources by at least two (2) circuit breakers in series (one Class 1E at the Class 1E buses and at least one non-Class 1E breaker at the CTG bus). Power to the breakers will be from appropriate DC sources.
B.7 The AAC power source shall not normally be directly connected to the preferred or onsite emergency AC power system for the unit affected by the blackout. In addition, the AAC system shall not be capable of automatic loading of shutdown equipment from the blacked-out unit unless licensed with such capability.	The ABWR AAC power source will not normally be connected to the preferred or onsite emergency AC power system. However, the COL applicant may use the CTG for other services (e.g. maintenance backup, etc.). The AAC power system will not automatically connect to or load any shutdown equipment on safety-related emergency buses. The AAC power source will automatically start upon occurrence of a LOPP event. It is connected automatically to the non-safety-related Plant Investment Protection (PIP) buses. It is capable of being manually connected to safety-related buses. It is also capable of being manually connected to non-safety power generation loads, condensate pumps, etc.).
Minimum Potential for Common Cause Failure	
B.8 There shall be minimal potential for common cause failure of the AAC power source(s). The following system features provide assurance that the minimal potential for common cause failure has been adequately addressed.	The ABWR AAC power source design contains a number of design and operational features which provide assurance of minimal potential for common cause failure.

Generating station conditions requiring RPS protective actions are defined in Chapter 16 (Technical Specifications).

(2) Variables

The generating station variables which are monitored cover the protective action conditions that are identified in Subsection 7.2.1.1.4.2.

(3) Sensors

A minimum number of LPRMs per APRM are required to provide adequate protective action. This is the only variable that has spatial dependence (IEEE-279, Paragraph 3.3).

(4) Operational Limits

Operational limits for each safety-related variable trip setting are selected with sufficient margin to avoid a spurious scram. It is then verified by analysis that the release of radioactive material following postulated gross failure of the fuel or the reactor coolant pressure boundary is kept within acceptable bounds. Design basis operational limits in Chapter 16 are based on operating experience and constrained by the safety design basis and the safety analyses.

(5) Margin Between Operational Limits

The margin between operational limits and the limiting conditions of operation (scram) for the Reactor Protection System are described in Chapter 16. The margin includes the maximum allowable accuracy error, sensor response times, and sensor setpoint drift.

(6) Levels Requiring Protective Action

Levels requiring protective action are provided in Chapter 16. These levels are design basis setpoints and are at least as limiting as the limiting safety system settings provided in Chapter 16.

(7) Ranges of Energy Supply and Environmental Conditions

The RPS 120 VAC power is provided by the four battery-powered inverters, for the SSLC, each with an alternate Class 1E 120 VAC supply. The batteries, which are designed for a two-hour minimum capacity, have sufficient stored energy to ride through switching transients in the switch yards in order to prevent switching transients from causing a scram. The alternate sources of 120V power are provided to each SSLC bus from transformers powered from the ~~6.9 kV~~ emergency diesel generators. Since there are three diesel

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7.4.1.3 Reactor Shutdown Cooling Mode–Instrumentation and Controls

(1) Function

The SDC mode of the RHR System is used during the normal or emergency reactor shutdown and cooldown. The RHR System P&ID is Figure 5.4-10 and the RHR System IBD is Figure 7.3-4.

The initial phase of the SDC mode is accomplished following insertion of the control rods and steam blowdown to the main condenser which serves as the heat sink.

Reactor shutdown cooling has three independent loops. Each loop consists of pump, valves, heat exchanger, and instrumentation designed to provide decay heat removal capability for the core. This mode specifically accomplishes the following:

(a) Reactor Shutdown–removes enough residual heat (decay and sensible) from the reactor vessel water to cool it to 60°C within 24 hours after the control rods are inserted, then maintains or reduces this temperature so that the reactor can be refueled and serviced. This mode is manually activated with the reactor pressure below 0.93 MPaG, with all three SDC loops available.

(b) Safe Shutdown (Emergency Shutdown) brings the reactor to a cold shutdown condition (< 100°C) within 36 hours after control rod insertion. This mode is manually activated with the reactor pressure below 0.93 MPaG, with two-out-of-three shutdown cooling loops available.

The RHR mode can accomplish its design objective by a preferred means by directly extracting reactor vessel water from the vessel shutdown nozzle and routing it to a heat exchanger and back to the vessel. Cooling water is returned to the vessel via the feedwater line (Loop A) and via the core cooling injection nozzles (Loops B and C).

(2) Classification

Electrical components for the reactor SDC mode of the RHR System are safety-related and are classified as Class 1E.

(3) Power Sources

medium voltage AC

This system utilizes normal plant power sources. These include ~~6900 VAC~~ for the pumps, 480 VAC/120 VAC instrument buses, and as backed up by DC

(7) Electrical Power Distribution System (EPDS)

(a) The following functions have transfer and control switches located on the Division I remote shutdown panel:

(i) ~~6.9~~ 4.16 kV feeder breaker: Unit auxiliary transformer A to ~~M/C E~~ Division I 4.16 kV bus

(ii) ~~6.9~~ 4.16 kV feeder breaker: Reserve auxiliary transformer A to ~~M/C E~~ Division I 4.16 kV bus

(iii) ~~6.9~~ 4.16 kV feeder breaker: Emergency diesel generator A to ~~M/C E~~ Division I 4.16 kV bus

(iv) ~~6.9~~ 4.16 kV feeder breaker: Combustion turbine generator to ~~M/C E~~ Division I 4.16 kV bus

(v) ~~6.9~~ 4.16 kV load breaker: M/C E to ~~P/C E20~~ Division I 480 VAC load center

(vi) 480V feeder breaker: TR to ~~P/C E20~~ Division I 480 VAC pump house load center

(b) The following functions have transfer and control switches located on the Division II remote shutdown panel:

(i) ~~6.9~~ 4.16 kV feeder breaker: Unit auxiliary transformer B to ~~M/C F~~ Division II 4.16 kV bus

(ii) ~~6.9~~ 4.16 kV feeder breaker: Reserve auxiliary transformer A to ~~M/C F~~ Division II 4.16 kV bus

(iii) ~~6.9~~ 4.16 kV feeder breaker: Emergency diesel generator B to ~~M/C F~~ Division II 4.16 kV bus

(iv) ~~6.9~~ 4.16 kV feeder breaker: Combustion turbine generator to ~~M/C F~~ Division II 4.16 kV bus

(v) ~~6.9~~ 4.16 kV load breaker: M/C F to ~~P/C F20~~ Division II 480 VAC load center

(vi) 480V feeder breaker: TR to ~~P/C F20~~ Division II 480 VAC pump house load center

(c) A ~~6.9~~ 4.16 kV M/C (E,F) voltmeter monitoring the divisional 4.16 kV buses is provided on RSS panels A,B, respectively.

(8) Flammability Control System (FCS)

(a) The following FCS equipment function has transfer and control switches located on both remote shutdown panels as indicated:

(i) Valve (cooling water inlet) B

(9) Atmospheric Control (AC) System

(a) Suppression pool level indication is provided on both RS panels.

(10) Makeup Water Condensate System (MUWC)

(a) Condensate storage pool level indication is provided on RS panel B.

(11) Suppression Pool Temperature Monitoring System (SPTM)

(a) Suppression pool temperature indication is provided on both RS panels.

RCIS demanding rod motion block or rod insertion for stability and protection control. These trip functions are shown in Figure 7.7-7

(7) Recirculation Pump Trip (RPT)

In the event of either (a) turbine trip or generator load rejection when reactor power is above a predetermined level (EOC RPT), (b) reactor pressure exceeds the high dome pressure trip setpoint, or (c) reactor water level drops below the Level 3 setpoint, the RPT logic will automatically trip off a group of four RIPs. The group of the RIPs being tripped is the same group which derives its power source directly from the ~~6.9~~ 13.8 kV buses (i.e., the group not having the M-G set interface).

The three inputs required to determine the preceding three RPT conditions are provided by the Reactor Protection System, the Feedwater Control System, and the Steam Bypass and Pressure Control System. These inputs consist of three sets of discrete signals for each of the end-of-cycle (EOC), high pressure and low level (Level 3) trip conditions. Each set represents the status of four channel outputs. A two-out-of-four logic is used by the RFC System to confirm the validity of the EOC trip condition. Two-out-of-three logic is used for the high pressure and Level 3 trip conditions. Any one of the three trip conditions can initiate a RPT. All switching logics are performed by the triplicate RFC controller. RPT is implemented by tripping the ~~gate turn off (GTO)~~ inverters in the adjustable speed drives.

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After tripping off the first group of four RIPs, if reactor water level continues to drop and reaches Level 2, the remaining six RIPs will be tripped, three immediately and the final three after a preset time delay. The implementation of the second RPT function is similar to the EOC RPT, using two-out-of-four confirmation logic. The level 2 trip signal is provided by the Nuclear Boiler System. All RPT functions are non-safety-related.

(8) Equipments

(a) Reactor Internal Pumps (RIPs)

The Reactor Recirculation System incorporates 10 RIPs with their impellers and diffusers internal to the reactor vessel. The RIPs themselves are mounted vertically onto and through the pump nozzles that are arranged in an equally-spaced ring pattern on the bottom head of the reactor pressure vessel. The RIPs are single stage, vertical pumps driven by variable speed induction motors. The pump speed is changable by varying the voltage and frequency output of the individual pump motor electrical power supply.

8.0 Electric Power

8.1 Introduction

8.1.1 Offsite Transmission Network

The description of the offsite transmission network is out of the ABWR Standard Plant scope, however there are interface requirements contained in Section 8.2.3 which must be complied with by the COL applicant.

8.1.2 Electric Power Distribution System

8.1.2.0 Definitions

The definitions used throughout Chapter 8 are consistent with Section 3 of IEEE-308 with the following important clarifications for the ABWR:

Division—The designation applied to a given safety-related system or set of components that enables the establishment and maintenance of physical, electrical, and functional independence from other redundant sets of components. (The term "safety-related" is added to the IEEE-308 definition.)

Load group—An arrangement of buses, transformers, switching equipment, and loads fed from a common power supply. (The last three words "...within a division" are deleted with respect to the IEEE-308 definition.) A load group may be safety-related or non-safety-related depending on its common power supply.

Safety-related—Any Class 1E power or protection system device included in the scope of IEEE-279 or IEEE-308. (This term is explicitly defined in IEEE-100, though not in IEEE-308.) Note that "safety-related" includes both electrical and non-electrical equipment, whereas "Class 1E" pertains only to electrical equipment (i.e., any equipment which has an electrical interface).

8.1.2.1 Description of Offsite Electrical Power System

The scope of the offsite electrical power system includes the entire offsite transmission network and the transmission lines coming into the switchyards to the termination of the bus duct and power cables at the input terminals of the ~~circuit breakers for the 6.9-kV switchgear.~~ main and reserve transformers. The COL applicant has design responsibility for portions of the offsite power system. The scope split is as defined in the detailed description of the offsite power system in Subsection 8.2.1.1.

[1612] The ~~1500~~ MVA main power transformer is a bank of three single phase transformers. One single phase installed spare transformer is provided.

A main generator circuit breaker capable of interrupting the maximum available fault current is provided. This allows the generator to be taken off line and the offsite transmission network to be utilized as a power source for the unit auxiliary transformers and their loads, both Class 1E and non-Class 1E. This is also the startup power source for the unit.

There are three unit auxiliary transformers, connected to supply power to three approximately equal load groups of equipment. The "Normal Preferred" power feed is from the unit auxiliary transformers so that there normally are no bus transfers required when the unit is tripped off the line.

There are two three winding RATs, each having one 13.8 kV secondary winding and one 4.16 kV winding which provide alternate preferred power to the connected loads.

~~One, three-winding 37.5 MV-A unit reserve auxiliary transformer (RAT) provides power via one secondary winding for the Class 1E buses as an alternate to the "Normal Preferred" power. The other secondary winding supplies reserve power to the non-Class 1E buses. This is truly a reserve transformer because unit startup is accomplished from the normal preferred power, which is backfed from the offsite transmission network over the main power circuit to the unit auxiliary transformers. The two low-voltage windings of the reserve transformer are rated 18.75 MV-A each.~~

At least 20 MW

~~A 9mW~~ combustion turbine generator is provided as an alternate AC power source. The unit is capable of providing power to non-Class 1E plant investment protection buses and Class 1E buses. The combustion turbine generator is non-safety-related.

8.1.2.2 Description of Onsite AC Power Distribution System

The 13.8 kV windings of the reserve auxiliary transformers (RATs) may be utilized to supply reserve power to the non-Class 1E power generation buses. The 4.16 kV windings of the RATs may be utilized to supply reserve power to the plant investment protection (PIP) buses and to the three Class 1E buses.

Three non-Class 1E buses and one Class 1E division receive power from the single unit auxiliary transformer assigned to each load group. Load groups A, B and C line up with Divisions I, II and III, respectively. ~~One winding of the reserve auxiliary transformer may be utilized to supply reserve power to the non-Class 1E buses either directly or indirectly through bus-tie breakers. The three Class 1E buses may be supplied power from the other winding of the reserve auxiliary transformer.~~

A combustion turbine generator (CTG) supplies automatic standby power to plant investment protection non-Class 1E loads. These loads are grouped on the three plant investment protection (PIP) buses as shown in Figure 8.3-1. The CTG also has the capability to be manually connected to any of the three Class 1E buses, for mitigation of the station blackout (SBO) event (see Subsection (9) of 8.3.1.1.7).

In general, motors larger than 300 kW are supplied from the ~~6.9 kV~~ medium voltage metal-clad (M/C) bus. Motors 300 kW or smaller but larger than 100 kW are supplied power from 480V power center (P/C) switchgear. Motors 100 kW or smaller are supplied power from 480V motor control centers (MCC). The ~~6.9 kV~~ medium voltage and 480V single line diagrams are shown in Figure 8.3-1.

During normal plant operation all of the non-Class 1E buses and two of the Class 1E buses are supplied with power from the main turbine generator through the unit auxiliary transformers. The remaining Class 1E bus is supplied from the ~~reserve auxiliary transformer.~~ second RAT. This division is immediately available, without a bus transfer, if the normal preferred power is lost to the other two divisions.

Three safety related, Class 1E diesel generator standby AC power supplies provide a separate onsite source of power for each Class 1E division when normal or alternate preferred power supplies are not available. The transfer from the normal preferred or alternate preferred power supplies to the diesel generator is automatic. The transfer back to the normal preferred or the alternate preferred power source is a manual transfer.

The Division I, II, and III standby AC power supplies consist of an independent ~~6.9~~ 4.16 kV Class 1E diesel generator (D/G), one for each division. Each D/G may be connected to its respective ~~6.9~~ 4.16 kV Class 1E switchgear bus through a circuit breaker located in the switchgear.

The standby AC power system is capable of providing the required power to safely shut down the reactor after loss of preferred power (LOPP) and/or loss of coolant accident (LOCA) and to maintain the safe shutdown condition and operate the Class 1E auxiliaries necessary for plant safety after shutdown.

The plant 480 VAC power system distributes sufficient power for normal auxiliary and Class 1E 480 volt plant loads. All Class 1E elements of the 480V power distribution system are supplied via the ~~6.9~~ 4.16 kV Class 1E switchgear and, therefore, are capable of being fed by the normal preferred, alternate preferred, standby diesel generator, or combustion turbine generator power supplies.

The 120 VAC non-Class 1E instrumentation power system, Figure 8.3-2, provides power for non-Class 1E control and instrumentation loads.

The Class 1E 120 VAC instrument power system, Figure 8.3-2, provides for Class 1E plant controls and instrumentation. The system is separated into Divisions I, II and III with distribution panels and local control panels fed from their respective divisional sources.

The 125 VDC power distribution system provides four independent and redundant onsite battery sources of power for operation of Class 1E DC power, control, and instrument loads. The 125 VDC non-Class 1E power control and instrument loads are supplied from three 125 VDC batteries located in the turbine building. A separate non-Class 1E 250V battery is provided to supply uninterruptible power to the plant computers and non-Class 1E DC motors (Figure 8.3-4).

The safety system and logic control (SSLC) for the Reactor Protection System (RPS) and Main Steamline Isolation Valves (MSIV) derives its power from four uninterruptible 120 VAC divisional buses (See Figure 8.3-3). The SSLC for the Emergency Core Cooling System (ECCS) derives its power from the four divisions of 125 VDC buses. The four buses provide the redundancy for various instrumentation, logic and trip circuits and solenoid valves. The SSLC power supply is further described in Subsection 8.1.3.1.1.2.

8.1.2.3 Safety Loads

The safety loads utilize various Class 1E AC and/or DC sources for instrumentation and motive or control power or both for all systems required for safety. Combinations of power sources may be involved in performing a single safety function. For example, low voltage DC power in the control logic may provide an actuation signal to control a 4.16 ~~6.9~~ kV circuit breaker to drive a large AC-powered pump motor. The systems required for safety are listed below:

(1) Safety System Logic and Control Power Supplies including the Reactor Protection System

(2) Core and Containment Cooling Systems

(a) Residual Heat Removal (RHR) System

(b) High Pressure Core Flooder (HPCF) System

(c) Automatic Depressurization System (ADS)

(d) Reactor Core Isolation Cooling (RCIC) System

(3) ESF Support Systems

(a) Diesel generator Sets and Class 1E AC/DC power distribution systems

(b) HVAC Emergency Cooling Water (HECW) System

(c) Reactor Building Cooling Water (RCW) System

(d) ~~Not Used~~ Reactor Service Water (RSW) System

(e) Standby Gas Treatment System (SGTS)

(f) Reactor Building Emergency HVAC System

(g) Control Building HVAC System

(h) High Pressure Nitrogen Gas Supply (HPIN) System

(i) Leak Detection and Isolation (LDI) System

(4) Safe Shutdown Systems

(a) Standby Liquid Control System (SLCS)

(b) Nuclear Boiler System (NBS)

(i) Safety/Relief Valves (SRVs)

(ii) Steam Supply Shutoff Portion

(c) Residual Heat Removal (RHR) System decay heat removal

(5) Class 1E Monitoring Systems

(a) Neutron Monitoring System (NMS)

(b) Process Radiation Monitoring System (PRMS)

(c) Containment Atmosphere Monitoring System (CAMS)

(d) Suppression Pool Temperature Monitoring System (SPTM)

For detailed listings of Division I, II and III loads, see Tables 8.3-1 and 8.3-2.

8.1.3 Design Bases

8.1.3.1 Safety Design Bases–Onsite Power

8.1.3.1.1 General Functional Requirements

8.1.3.1.1.1 Onsite Power Systems–General

The unit's total Class 1E power load is divided into three divisions. Each division is fed
4.16 by an independent ~~6.9~~ kV Class 1E bus, and each division has access to one onsite and two offsite power sources. An additional power source is provided by the combustion turbine generator (CTG). A description of the CTG is provided in Subsection 9.5.11.

Each of the two normally energized offsite power feeders (i.e., normal preferred and alternate preferred power) are provided for the Divisions I, II and III Class 1E systems. Normally two divisions are fed from the normal preferred power source and the remaining division is fed from the alternate preferred power source. Both feeders are used during normal plant operation to prevent simultaneous de-energization of all divisional buses on the loss of only one of the offsite power supplies. The transfer to the other preferred feeder is manual. During the interim, power is automatically supplied by the diesel generators.

The redundant Class 1E electrical divisions (Divisions I, II, and III) are provided with separate onsite standby AC power supplies, electrical buses, distribution cables, controls, relays and other electrical devices. Redundant parts of the system are physically separated and electrically independent to the extent that in any design basis

event with any resulting loss of equipment, the plant can still be shut down with the remaining two divisions. Independent raceway systems are provided to meet cable separation requirements for Divisions I, II, and III.

Divisions I, II, and III standby AC power supplies have sufficient capacity to provide power to all their respective loads. Loss of the preferred power supply, as detected by 4.16 ~~6.9~~ kV Class 1E bus under-voltage relays, will cause the standby power supplies to start and connect automatically, in sufficient time to safely shut down the reactor or limit the consequences of a design basis accident (DBA) to acceptable limits and maintain the reactor in a safe condition. The standby power supplies are capable of being started and stopped manually and are not stopped automatically during emergency operation unless required to preserve integrity. Automatic start will also occur on receipt of a Level 1 1/2 signal (HPCF initiate for Divisions II and III), Level 1 signal (RHR initiate for Division I) and high drywell pressure.

4.16 The Class 1E ~~6.9~~ kV Divisions I, II, and III switchgear buses, and associated ~~6.9~~ 4.16 kV diesel generators, 480 VAC distribution systems, and Divisions I, II, III and IV, 120 VAC and 125 VDC power and control systems conform to Seismic Category I requirements. This equipment is housed in Seismic Category I structures except for some control sensors associated with the Reactor Protection System [Subsection 9A.5.5.1], and the Leak Detection System [Subsection 9A.5.5.7]. Seismic Qualification is in accordance with IEEE-344 (Section 3.10).

In addition, non-safety-related equipment are designed to resist failure that could prevent any safety-related equipment from performing its nuclear safety-related function [Subsection 3.2.5.1, item (5)].

8.1.3.1.1.2 Safety System Logic and Control Power Supply System Design Bases

In order to provide redundant, reliable power of acceptable quality and availability to support the safety logic and control functions during normal, abnormal and accident conditions, the following design bases apply:

(1) SSLC power has four separate and independent Class 1E inverter uninterruptible constant voltage constant frequency (CVCF) power supplies each backed by separate Class 1E batteries.

(2) Provision is made for automatic switching to the alternate bypass supply from its respective division in case of a failure of the inverter power supply. The inverter power supply is synchronized in both frequency and phase with the alternate bypass supply, so that unacceptable voltage spikes will be avoided in case of an automatic transfer from normal to alternate supply. The SSLC uninterruptible power supply complies with IEEE-944 (Reference 8.1-1).

8.2 Offsite Power Systems

8.2.1 Description

8.2.1.1 Scope

This section provides a description of the design and performance requirements for the offsite power system. The offsite power system, as defined in the USNRC Standard Review Plan Section 8.2, consists of the following:

Applicant Scope

(1) The offsite transmission network [including the tie lines to the switchyard(s)]

(2) The plant switchyard(s)

(3) The separated switching stations

(4) The high voltage tie lines from the switching stations to the main power transformers, and to the reserve auxiliary ~~transformer~~ transformers

(5) The main step-up power ~~transformers~~ transformer

(6) The reserve auxiliary ~~transformer~~ transformers

ABWR Standard Plant Scope

(7) The three unit auxiliary transformers

(8) The plant main generator

(9) The combustion turbine generator

(10) The isolated phase buses from the main power transformer to the main generator circuit breaker, and to the unit auxiliary transformers

(11) The main generator circuit breaker

(12) ~~The non-segregated phase buses from the unit auxiliary transformers to the input terminals of the non safety related medium voltage (6.9 kV) switchgear, the non safety related medium voltage switchgear (A4, B4, C4) and the power cables form the non safety related medium voltage switchgear to the safety-related switchgear.~~ The non-segregated phase buses from the unit auxiliary transformers (UATs) to the input terminals of the non-safety-related medium voltage (13.8 kV) switchgear, the cable buses from the UATs to the input terminals of the plant investment protection (PIP) medium voltage (4.16 kV) switchgear.

(13) The non-segregated phase bus and power cables from the reserve auxiliary ~~transformer~~ transformers to the input terminals of the non-safety-related and safety-related medium voltage (~~6.9 kV~~ 4.16 kV and 13.8 kV) switchgear

(14) The power cables from the combustion turbine generator to the input terminals of the medium voltage 4.16 kV and 13.8 kV ~~(6.9 kV)~~ switchgear. ~~including the disconnect and interconnecting bus~~

The design scope for the ABWR ends at the low voltage terminals of the main power transformers transformer and the low voltage terminals of the reserve auxiliary ~~transformer~~. Although the remainder of the offsite power system is not in the scope of the ABWR design, the ABWR design is based on a power system which meets certain design concepts. Design bases (10CFR52 interface requirements) consistent with these concepts are included in Subsection 8.2.3. Meeting the design bases presented in Subsection 8.2.3 will ensure that the power system within the design scope for the ABWR meets all regulatory requirements. Meeting the conceptual design bases presented in Section 8.2.5 will ensure that the total power system design is consistent and meets all regulatory requirements.

The portions of the offsite power system which fall under the design responsibility of the COL applicant will be unique to each COL application. It is the responsibility of all concerned parties to insure that the total completed design of equipment and systems falling within the scope of this section be in line with the description and requirements stated in. See Subsection 8.2.4 for a detailed listing and description of the COL license information.

8.2.1.2 Description of Offsite Power System

The offsite electrical power system components within the scope of the applicant include items (1) through (6) identified in Subsection 8.2.1.1. The remaining items (7) through (14) are within the scope of the ABWR standard plant design.

When used for normal operation, each preferred power supply is sized to supply the maximum expected coincident Class 1E and non-Class 1E loads.

The normal and alternate preferred power circuits are designed in accordance with industry-recommended practice in order to minimize the likelihood that they will fail while operating under the environmental conditions (such as, wind, ice, snow, lightning, temperature variations, or flood) to which they are subject.

Performance and operating characteristics of the normal and alternate preferred power circuits are required to meet operability and design-basis requirements, such as: (1) the ability to withstand short-circuits, (2) equipment capacity, (3) voltage and frequency transient response, (4) voltage regulation limits, (5) step load capability, (6) coordination of protective relaying and (7) grounding.

Air cooled isolated phase bus duct is sized to provide its load requirements and withstand fault currents until the fault is cleared. It is rated approximately [45] kA ~~36 kA~~ and provides for a power feed to the main power transformer and unit auxiliary transformers from the main generator. The sections of the isolated phase bus supplying the unit auxiliary

[40]

transformers are rated less than ~~36~~ kA as appropriate to the load requirements (see Figure 8.3-1).

A generator circuit breaker is provided in the isolated phase bus duct at an intermediate location between the main generator and the main power transformer. The generator circuit breaker provided is capable of interrupting a maximum ~~fault current of 275 kA symmetrical and 340 kA asymmetrical~~ at 5 cycles after initiation of the fault. This corresponds to the maximum allowable interface fault current specified in Subsection 8.2.3. The main generator circuit breaker allows the generator to be taken offline and the offsite transmission network to be utilized as a power source by backfeeding to the unit auxiliary transformers and their loads, both Class 1E and non-Class 1E. This is also the startup power source for the unit. Short circuit analysis will be performed in accordance with IEEE 141 and/or other acceptable industry standards or practices to determine fault currents.

symmetrical and asymmetrical fault current of 440 kA momentary

Unit synchronization will normally be through the main generator circuit breaker. A coincidental three-out-of-three logic scheme and synchro-check relays are used to prevent faulty synchronizations.

It is a design basis requirement that synchronization be possible through the switching station's circuit breakers (Subsection 8.2.5 (24)).

Dual trip coils are provided on the main generator circuit breakers and control power is supplied from redundant load groups of the non-Class 1E onsite 125 VDC power system.

Replace paragraph "There are three unit . . ." with **Insert A** on next page

~~There are three unit auxiliary transformers. Each transformer has three windings and each transformer feeds one Class 1E bus directly, two non Class 1E buses directly, and one non Class 1E bus indirectly through a non 1E to non 1E bus tie. The medium voltage buses are in a three load group arrangement with three non Class 1E buses and one Class 1E bus per load group. Each unit auxiliary transformer has an oil/air rating at 65°C of 37.5 MV-A for the primary winding and 18.75 MV-A for each secondary winding. The forced air/forced oil (FOA) rating is 62.5 and 31.25/31.25 MV-A — respectively. The normal loading of the six secondary windings of the transformers is balanced with the heaviest loaded winding carrying a load of 17.7 MV-A. The heaviest transformer loading occurs when one of the three unit auxiliary transformers is out of service with the plant operating at full power. Under these conditions the heaviest loaded winding experiences a load of 21.6 MV-A, which is about two thirds of its forced air/forced oil rating.~~

Disconnect links are provided in the isolated phase bus duct feeding the unit auxiliary transformers so that any single failed transformer may be taken out of service and operation continued on the other two unit auxiliary transformers. One of the buses normally fed by the failed transformer would have to be fed from the reserve auxiliary

Insert A:

There are three UATs; each transformer has a primary winding to match the generator voltage and each transformer uses automatic tap changers to improve voltage regulation on the plant medium voltage buses. Two of the UATs are rated at approximately 65/86 MVA (ONAN/ONAF) and provide both 13.8 kV and 4.16 kV secondary windings. The former feeds the power generation (PG) buses, and the latter independently feeds the plant investment protection (PIP) buses A and B, and the Class 1E Division I and II buses. The third UAT is rated at approximately 20/26 MVA (ONAN/ONAF) and provides only 4.16 kV power only to PIP bus C and independently to Class 1E buses in Division 3. Each Class 1E safety bus is directly connected to its corresponding UAT through a dedicated non-safety stub bus. In normal operation, significant margin is provided because the transformers are operating near their ONAN rating. If the transformers are supplying safety loads only, the margin is significantly increased.

transformer in order to keep all reactor internal pumps operating so as to attain full power. The reserve auxiliary transformer is sized for this type of service.

Replace paragraph *"One, three winding . . ."* with **Insert B** on next page

~~One, three winding 37.5 MV-A reserve auxiliary transformer provides power as the "Alternate Preferred" power to the "Normal Preferred" power. One of the equally rated secondary windings supplies reserve power to the nine (three through cross ties) non-Class 1E buses and the other winding supplies reserve power to the three Class 1E buses. The combined load of the three Class 1E buses is equal to the oil/air the rating of the transformer winding serving them. This is equal to 60% of the forced air/forced oil (FOA) rating of the transformer winding. The transformer is truly a reserve transformer because unit startup is accomplished from the normal preferred power, which is backfed over the main power circuit to the unit auxiliary transformers. The reserve auxiliary transformer serves no startup function. The operational configurations are such that the FOA ratings of the reserve auxiliary transformer, or any unit auxiliary transformer, will not be exceeded under any operating mode (Subsection 8.2.4.5).~~

The normal and alternate offsite preferred power circuits are designed with sufficient capacity and capability to limit variations of the operating voltage of the onsite power distribution system to a range appropriate to ensure: (1) normal and safe steady-state operation of all plant loads, (2) starting and acceleration of the limiting drive system with the remainder of the loads in service, and (3) reliable operation of the control and protection systems under conditions of degraded voltage [Subsection 8.3.1.1.7 (8)]. Specifically, the unit auxiliary transformers and the reserve auxiliary ~~transformer~~ transformers are designed to limit the voltage variation of the onsite power distribution system to ±10% of load rated voltage during all modes of steady state operation and a voltage dip of no more that 20% during motor starting.

Voltage levels at the low-voltage terminals of the unit and reserve auxiliary transformers will be analyzed to determine the maximum and minimum load conditions that are expected throughout the anticipated range of voltage variations of the offsite transmission system and the main generator. Separate analyses will be performed for each possible circuit configuration of the offsite power supply system.

The unit and reserve auxiliary transformers are designed and constructed to withstand the mechanical and thermal stresses produced by external short circuits. In addition, these transformers meet the corresponding requirements of the latest revisions of ANSI Standard C57.12.00. See Subsection 8.2.3(8) for interface requirements on the main step-up transformers and the reserve auxiliary transformer. See Subsection 8.2.3(10) for interface requirements on the high-voltage circuit breakers and disconnect switches.

The non-segregated phase bus that connects the unit auxiliary and reserve auxiliary transformers to their respective ~~the 6.9 kV~~ switchgear is sized to supply its load requirements and rated to withstand fault currents until the fault is cleared.

Insert B:

There are two RATs; each transformer has a primary winding of 345 kV corresponding to the switchyard voltage and each transformer also uses tap changers to improve voltage regulation on the plant medium voltage buses. The two RATs are each rated approximately 65/86 MVA and each provides both 13.8 kV and 4.16 kV secondary windings. The 13.8 kV winding of RAT A feeds an intermediates bus which, in turn feeds the power generation buses A1 and C1 and the electric boiler. The 13.8 kV winding of RAT B feeds the CTG bus which, in turn feeds the power generation buses B1 and D1. The 13.8 kV windings feed the power generation buses and are sized to directly replace the corresponding 13.8 kV windings of the UATs. The plant can operate at 100% power with any one UAT or RAT out of service and still provide two offsite power feeds to the three class 1E safety buses.

The 4.16 kV winding of RAT A provides power to the three PIP buses and independently to the three Class 1E safety buses. The CTG bus fed from RAT B allows the combustion turbine generator to operate a single condensate pump and, through an intervening 24 MVA 13.8/4.16 kV transformer, the three PIP and three Class 1E safety buses. The 4.16 kV winding of RAT B additionally provides power to the three PIP and three Class 1E safety buses.

Each Class 1E safety bus is directly connected to RAT A through a dedicated non-safety stub bus and either RAT 4.16 kV winding can separately supply the loads of all Class 1E safety buses. The RAT B 13.8 kV secondary is designed to allow full load operation of the CTG and, if offsite power is completely lost, the CTG can supply any combination of two PIP or two Class 1E safety buses. Although the RATs normally provide power to one Class 1E safety bus, operating at their maximum expected loads corresponds approximately to slightly more than their ONAN rating and therefore provides significant margin. That margin is improved if either RAT is supplying only safety loads.

Redundant offsite system circuits derive their control, protection, and instrument DC power from redundant non-Class 1E DC sources that are independent of the Class 1E DC sources.

8.2.1.3 Separation

The location of the main power transformer, unit auxiliary transformers, and reserve auxiliary ~~transformer~~ transformers are shown on Figure 8.2-1. The reserve auxiliary ~~transformer is~~ are separated from the main power and unit auxiliary transformers by a minimum distance of 15.24m, or by barriers. It is a requirement that the 15.24m minimum separation be maintained between the switching stations and the incoming tie lines (see Section 8.2.3). The transformers are provided with oil collection pits and drains to a safe disposal area.

Reference is made to Figures 8.3-1 for the single line diagrams showing the method of feeding the loads. The circuits associated with the alternate offsite circuit from the reserve auxiliary ~~transformer~~ transformers to the Class 1E buses are separated by walls or floors, or by at least 15.24m, from the main and unit auxiliary transformers. The circuits associated with the normal preferred offsite circuit from the unit auxiliary transformers to the Class 1E buses are separated by walls or floors, or by at least 15.24m, from the reserve auxiliary ~~transformer.~~ transformers. Separation of the normal preferred and alternate preferred circuits is accomplished by floors and walls over their routes through the Turbine, Control and Reactor Buildings except within the switchgear rooms where they are routed to opposite ends of the same switchgear lineups.

The normal preferred feeds from the unit auxiliary transformers are routed around the outside of the Turbine Building in an electrical tunnel from the unit auxiliary transformers to the Turbine Building switchgear rooms as shown on Figure 8.2-1. (An underground duct bank is an acceptable alternate.) From there the feeds to the Reactor Building exit the Turbine Building and continue across the roof on the Divisions I and III side of the Control Building (Figure 8.2-1, Sheet 3). They drop down the side of the Control Building in the space between the Control and Reactor Buildings where they enter the Reactor Building and continue on through the Divisions I and III side of the Reactor Building to the respective Class 1E switchgear rooms in the Reactor Building.

The alternate preferred feeds from the reserve auxiliary transformer are routed inside the Turbine Building. The Turbine Building switchgear feed from the reserve auxiliary transformer is routed directly to the Turbine Building switchgear rooms. The feed to the Control Building is routed in corridors outside of the Turbine Building switchgear rooms. It exits the Turbine Building and crosses the Control Building roof on the opposite side of the Control Building from the route for the normal preferred power feeds. The steam tunnel is located between the normal preferred feeds and the alternate preferred feeds across the stepped roof of the Control Building. The alternate preferred power feed turns down between the Control and Reactor Building and enters

delete paragraph (cont'd)

~~the Reactor Building on the Division II side of the Reactor Building. From there it continues on to the respective switchgear rooms in the Reactor Building.~~

Feeder circuit breakers from the unit auxiliary and reserve auxiliary transformers to the medium voltage ~~(6.9 kV)~~ switchgear are interlocked to prevent paralleling the normal and alternate power sources.

, except for manual bus transfer.

Instrument and control cables associated with the normal preferred power circuits are separated [i.e., by 15.24m, or by walls or floors] from the instrument and control cables associated with the alternate preferred power circuits; with exception of the circuits in the control room, the circuits at the control and instrument DC power sources, and the interlock circuitry required to prevent paralleling of the two offsite sources. However, these circuits are electrically isolated and separated to the extent practical, and are not routed together in the same raceway. The reserve auxiliary ~~transformer~~ power, instrument and control cables do not share raceways with any other cables. The instrumentation and control circuits for the normal and alternate preferred power shall not rely on a single common DC power source [see Subsection 8.2.3 items (13) and (15)].

transformers

The instrumentation and control cables for the unit auxiliary transformers and the main generator circuit breaker may be routed in the raceways corresponding to the load group of their power source.

Class 1E rotating equipment, which could produce potential missile hazards, are not located in the same rooms as feeder circuits from the offsite to the Class 1E buses, unless protective barriers are installed to preclude possible interaction between offsite and onsite systems.

A combustion turbine generator (CTG) supplies standby power to the non-Class 1E buses which supply the non-Class 1E plant investment protection (PIP) loads. It is ~~a~~ ~~9~~ MW rated self-contained unit which is capable of operation without external auxiliary systems. Although it is located on site, it is treated as an additional offsite source in that it supplies power to multiple load groups. In addition, manually controlled breakers provide the capability of connecting the combustion turbine generator to any of the Class 1E buses if all other AC power sources are lost.

at least [20]

In this way, the CTG provides a second "offsite" power source to any Class 1E bus being fed from the reserve auxiliary ~~transformer~~ while the associated unit auxiliary transformer is out of service.

transformers

within the plant security boundary

The combustion turbine generator (CTG) is located ~~in the Turbine Building~~, and is shown on Figure 8.2-1, Sheet 2. The CTG standby power feed and instrument and control cables ~~for the Turbine Building~~ are routed directly to the switchgear rooms in the Turbine Building. The power feeders and instrument and control cables to the

Reactor Building are routed adjacent to the alternate preferred feeds across the Control and Reactor Buildings in their own raceway.

8.2.2 Analysis

In accordance with the NRC Standard Review Plan (NUREG-0800), Table 8-1 and Section 8.2, the offsite power distribution system is designed consistent with the following criteria, so far as it applies to the non-Class 1E equipment. Any exceptions or clarifications are so noted.

8.2.2.1 General Design Criteria

(1) GDC 5 and RG 1.81—Sharing of Structures, Systems and Components

The ABWR is a single unit plant design. Therefore, these criteria are not applicable.

(2) GDC 17—Electric Power Systems

Each circuit of the preferred power supply is designed to provide sufficient capacity and capability to power equipment required to ensure that: (1) Fuel design limits and design conditions of the reactor coolant pressure boundary will not be exceeded as a result of anticipated operational occurrences, and (2) In the event of plant design-basis accidents, the core will be cooled, and containment integrity and other vital functions will be maintained.

As shown in Figure 8.3-1, each of the Class 1E divisional ~~6.9~~ 4.16 kV M/C buses can receive power from multiple sources. There are separate utility feeds from the offsite transmission network (via the main power ~~transformer~~ transformer/UAT and the reserve auxiliary ~~transformer~~ transformers). The unit auxiliary transformer output power feeds and instrumentation and control circuits and the reserve auxiliary transformer output power feeds and instrumentation and control circuits are routed by two completely separate paths through the yard, the Turbine Building, Control Building and Reactor Building to their destinations in the electrical equipment rooms and main control room. The transformers are provided with separate oil collection pits and drains to a safe disposal area.

Separation of offsite equipment is discussed in Subsection 8.2.1.3. The plant fire protection system is discussed in Section 9.5.1. Although these preferred power sources are non-Class 1E, such separation and provision assure the physical independence requirements of GDC 17 are preserved.

Switching and lightning surge protection is provided by the station grounding and surge protection systems described in Appendix 8A, and by the independent feeds (i.e., normal and alternate preferred power circuits

It is a requirement that the total design provided by GE and the applicant meet the requirements of this IEEE standard as modified by the specific additional requirements and explanatory statements in Table 8.2-1. The additional requirements are more restrictive than the requirements which they replace or modify from the IEEE standard. Any stated requirements in Tier 2 which are in conflict with the requirements stated in this standard take precedence over the requirements of the standard.

8.2.3 Interface Requirements

The standard design of the ABWR is based on certain assumptions concerning the design bases which shall be met by the COL applicant in designing the portion of the offsite power system in his scope, as defined in Subsection 8.2.1.1. Those design bases assumptions are listed here which the COL applicant shall meet.

(1) The offsite system shall consist of a minimum of two independent offsite transmission circuits from the transmission network.

(2) Voltage variations of the offsite transmission network during steady state operation shall not cause voltage variations at the loads of more than plus or minus 10% of the loads nominal ratings.

(3) The normal steady state frequency of the offsite transmission network shall be within plus or minus 2 hertz of 60 hertz during recoverable periods of system instability.

(4) The offsite transmission circuits from the transmission network through and including the main step-up power and reserve auxiliary transformers shall be sized to supply their load requirements, during all design operating modes, of their respective Class 1E divisions and non-Class 1E load groups.

, unit auxiliary

(5) The impedence of the main step-up power and reserve auxiliary transformers shall be compatible with the interrupting capability of the plant's circuit interrupting devices.

(6) The independence of offsite transmission power, instrumentation, and control circuits shall be compatible with the portion of the offsite transmission power, instrumentation, and control circuits within the ABWR Standard Plant scope.

(7) Instrumentation and control system loads shall be compatible with the capacity and capability design requirements of DC systems within the ABWR Standard Plant scope.

8.2.4 COL License Information

8.2.4.1 Periodic Testing of Offsite Equipment

Appropriate plant procedures shall include periodic testing and/or verification to ensure the following:

(1) The normal and alternate offsite power circuits are verified to be energized and connected to the appropriate Class 1E distribution system division at least once every 12 hours.

(2) The instrumentation, control, and protection systems, equipment, and components associated with the normal and alternate offsite preferred circuits are properly calibrated and perform their required functions.

(3) The required Class 1E and non-Class 1E loads can be powered from their designated preferred power supply within the capacity and capability margins specified in Tier 2 for the offsite system circuits.

(4) The loss of the offsite preferred power supply can be detected.

(5) Switching between preferred power supplies can be accomplished.

(6) The batteries and chargers associated with the preferred power system can meet the requirements of their design loads.

(7) The generator breaker can open on demand. (Note: The breaker's actual opening and closing mechanisms are inherently confirmed during the shutdown and synchronizing processes. Trip circuits shall be periodically verified during shutdown periods while the breaker is open.)

(8) Isolated and non-segregated phase bus ducts are inspected and maintained such that they are clear of debris, fluids, and other undesirable materials. Also, terminals and insulators are inspected, cleaned and tightened, as necessary.

The test and inspection intervals will be established and maintained according to the guidelines of IEEE-338, Section 6.5, as appropriate for non-Class 1E systems (i.e., Items (4) and (7) of Section 6.5.1 are not applicable).

8.2.4.2 Procedures when a Reserve or Unit Auxiliary Transformer is Out of Service

Appropriate plant operating procedures will be imposed whenever ~~the~~ a reserve auxiliary transformer or a unit auxiliary transformer is out of service.

Note that the Class 1E safety buses will have two preferred power sources with any one UAT or RAT failure.

8.2.4.3 Offsite Power Systems Design Bases

Interface requirements for the COL applicant offsite power systems design bases are provided in Subsection 8.2.3.

8.2.4.4 Offsite Power Systems Scope Split

Interface requirements for the COL applicant pertaining to offsite power systems scope split are provided in Subsection 8.2.3.

8.2.4.5 Capacity of Auxiliary Transformers

Appropriate plant procedures shall be provided to assure ~~FOA~~ ONAF ratings of ~~the~~ any reserve auxiliary transformer, or any unit auxiliary transformer, will not be exceeded under any operating mode (Subsection 8.2.1.2).

8.2.5 Conceptual Design

(1) Voltage variations of the offsite transmission network during steady state operation do not cause variations at the loads of more than plus or minus 10% of the loads nominal ratings.

(2) The normal steady state frequency of the offsite transmission network are within plus or minus 2 hertz of 60 hertz during recoverable periods of system instability.

(3) The offsite transmission lines from the transmission network to the main power and reserve switching stations do not have a common takeoff structure or use common structure for support.

(4) The tie lines from the main step-up power and reserve auxiliary switching stations to their respective transformers do not have a common takeoff structure or use common structures for support.

(5) The two offsite circuits from the transmission network to the transformers are designed to minimize their simultaneous loss as a result of failure of any transmission tower, crossing line, single breaker, switchgear bus, or cable.

(6) The main and reserve offsite power systems' transmission lines from the transmission network and tie lines do not cross over each others offsite lines or switching station equipment.

(7) The offsite circuits are designed in accordance with industry recommended practice in order to minimize the likelihood that they will fail while operating under the environmental conditions (such as, wind, ice, snow, lightning, temperature variations, or flood) to which they are subject.

(8) System studies demonstrate that the offsite transmission network will not degrade below a level consistent with the availability goals of the plant as a result of contingencies such as loss of any of the following elements: Nuclear power generating unit, largest generating unit, most critical transmission circuit or intertie, or largest load.

(9) Separation between the main and reserve offsite circuits (e.g., the transmission lines, tie lines, switching stations, transformers, bus ducts, and power, instrumentation and control cables), is at least 15.24 meters and is greater than the height of any component which could cause loss of both offsite circuits up to the point at which the component can no longer affect both circuits. (Note: the switching stations may be in the same switchyard or separated switchyards provided the required minimum separation is maintained).

transformers are

(10) The reserve auxiliary ~~transformer is~~ separated by a minimum of 15.24m from the unit auxiliary transformers.

(11) Instrumentation and control circuits of the main power offsite circuit (i.e., normal preferred power circuit) are separated from the instrumentation and control circuits for the reserve power circuit (i.e., alternate preferred power circuit) in the same manner as described in (9) and (10) above.

(12) Lightning arresters are provided for each phase of all tie lines connecting the plant electrical systems to the switchyard and transmission network. These arresters are connected to the high-voltage terminals of the main step-up power and reserve auxiliary transformers. Transformers are also grounded.

(13) The main step-up power and reserve auxiliary transformers are provided with separate oil collection pits and drains to safe disposal area, and are provided with fire protection deluge systems as specified in Section 9A.4.6.

(14) Analyses of the incoming transmission lines assures that the expected availability of the offsite power is as good as the assumptions made in performing the plant probability risk analysis (see item 5.1.2 of Table 8.2-1, and Chapter 19).

(15) The main step-up power and the reserve auxiliary transformers are designed to meet the requirements of ANSI Standard C37.06 (Reference 8.2-1), General Requirements for Liquid-Immersed Distribution, Power Regulating Transformers.

(16) The main power transformer consists of three normally energized single-phase transformers with an additional installed spare. Provisions are made to permit connecting and energizing the spare transformer in no more than 12 hours following a failure of one of the normally energized transformers.

(17) The offsite transmission circuits from the transmission network through and including the main step-up power and reserve auxiliary transformers are designed and constructed to withstand the mechanical and thermal stresses from the worst case faults.

The calculated rating for the main step-up power transformer is approximately 1612 MVA with a nominal voltage of 27 kV, and with taps at 105%, 102.5%, 100%, 97.5%, and 95% of nominal voltage. The main transformer consists of three singe-phase units, with an installed spare, each individually rated at approximately 537.5 MVA.

(18) ~~The calculated rated conditions for the main step-up power transformer is 1500 MV-A at a power factor of 0.9 and a voltage of 26.325 kV plus or minus 10%.~~ The main step-up power transformer and high voltage circuit has sufficient impedance to limit the primary side maximum available fault current contribution from the system to that required by the main generator output circuit breaker as defined in Subsection 8.2.1.2.

(19) ~~The calculated rated conditions for the reserve auxiliary transformer is 37.5 MV-A at a 0.9 power factor.~~ When coordinated with the design of the reserve auxiliary transformer, the offsite transmission system circuit supports a maximum allowable voltage dip of 20% during the starting of large motors.

The calculated rating for the two reserve auxiliary transformers are approximately 65/86 MVA (ONAN/ONAF).

(20) The offsite transmission circuits from the transmission network through and including the main step-up power and reserve auxiliary transformers are sized to supply their load requirements, during all design operating modes, of their respective Class 1E divisions and non-Class 1E load groups.

(21) The impedances of the main step-up power transformer, unit auxiliary and reserve auxiliary transformers ~~transformer~~ are compatible with the interrupting capability of the plant's circuit interrupting devices.

(22) Circuit breakers and disconnect switches are sized and designed in accordance with the latest revision of ANSI Standard C37.06 (Reference 8.2-1), Preferred Ratings and Related Capabilities for AC high-Voltage Circuit Breakers Rated on a Symmetrical Current Basis. All circuit breakers are purchased new (i.e, not refurbished used ones) in accordance with resolution of NRC Information Notice 88-46 (see Question/Response 435.56 in Subsection 20.3.8).

(23) The main power switching station has at least two full capacity main buses arranged such that:

(a) Any incoming or outgoing transmission line can be switched without affecting another line;

Table 8.2-1 Additional Requirements IEEE-765

IEEE-765 Reference		Requirement or Explanatory Note
4.1	General	Tier 2 Figure 8.3-1 should be used as the reference single line instead of the IEEE Std example, Figures 2, (a), (b) and (c).
4.2	Safety Classification	The separation criteria called for in Subsection 8.2.1.3 must be met.
4.5	Availability	The ABWR design utilizes direct connection of the two preferred power circuits to the Class 1E buses.
5.1.2	Transmission System Reliability	Additional analysis is required per Section 8.2.3(4).
5.1.3	Transmission System Independence	
	5.1.3.2	Specific requirements for tolerance to equipment failures are stated in Tier 2 and must be met.
	5.1.3.3	Since a separation of at least 15.24m is required for the exposed circuits, a common takeoff structure cannot be used.
5.3.2	Class 1E Power System Interface Independence	(See 5.1.3.3 comments)
5.3.3	Connections with Class 1E Systems	
	5.3.3.2	Automatic dead-bus transfers are used to transfer from the preferred power supply to the onsite AC source. Manual ~~dead-bus~~ transfers are used between preferred power supplies, and to transfer from the onsite source back to the preferred power supply. Automatic live-bus transfers are not required and are not used.
	5.3.3.3	Only standby power sources may be paralleled with the preferred power sources for load testing. The available fault current must be less than the rating of the breakers. It is not required and not allowed for the normal and alternate preferred power supply breakers for a bus to be closed simultaneously so there is no time that the available fault current at a bus exceeds the equipment rating.
7.0	Multi-Unit Considerations	The ABWR is a single unit design, therefore there is no sharing of preferred power supplies between units.

delete text

(except a manual CTG bus connection for dual unit plants).

8.3 Onsite Power Systems

(See Section 8.3.3 for information generally applicable to all onsite power equipment.)

8.3.1 AC Power Systems

The onsite power system interfaces with the offsite power system at the input terminals to the supply breakers for the normal, alternate, and combustion turbine generator power feeds to the medium voltage (~~6.9 kV~~) switchgear. ~~It is~~ a three load group system with each load group consisting of a non-Class 1E and a Class 1E portion. The three load groups of the Class 1E power system (i.e., the three divisions) are independent of each other. The principal elements of the auxiliary AC electric power systems are shown on the single line diagrams (SLD) in Figures 8.3-1 through 8.3-3.

4.16 kV and 13.8 kV

It is a four load group power generation bus system and

PIP

Each Class 1E division has a dedicated safety-related, Class 1E diesel generator, which automatically starts on high drywell pressure, low reactor vessel level or loss of voltage on the division's ~~6.9~~ kV bus. The signals generated from high drywell pressure and low reactor vessel level are arranged in two-out-of-four logic combinations, and are utilized to sense the presence of a LOCA condition and subsequently start the diesel. These signals also initiate the emergency core cooling systems.

4.16

The loss of voltage condition and the degraded voltage condition are sensed by independent sets of three undervoltage relays (one on each phase of the ~~6.9~~ kV bus) which are configured such that two-out-of-three trip states will initiate circuitry for transferring power from offsite power to the onsite diesel generator (after a time delay for the degraded voltage condition). The primary side of each of the instrument potential transformers (PTs) is connected phase-to-phase (i.e., a "delta" configuration) such that a loss of a single phase will cause two of the three undervoltage relays to trip, thus satisfying the two-out-of-three logic. (For more information on the degraded voltage condition and associated time delays, etc., see Subsection (8) of 8.3.1.1.7.)

4.16

4.16

Each ~~6.9~~ kV Class 1E bus feeds its associated 480V unit ~~substation~~ through a ~~6.9~~ kV/480~~/277~~V power center transformer.

substations

Standby power is provided to plant investment protection non-Class 1E loads in all three load groups by a combustion turbine generator located in the turbine building.

4.16 kV or 13.8 kV

AC power is supplied at ~~6.9~~ kV for motor loads larger than 300 kW and transformed to 480V for smaller loads. The 480V system is further transformed into lower voltages as required for instruments, lighting, and controls. In general, motors larger than 300 kW are supplied from the ~~6.9~~ kV buses. Motors 300 kW or smaller but larger than 100 kW are supplied power from 480V switchgear. Motors 100 kW or smaller are supplied power from 480V motor control centers.

4.16 kV or 13.8 kV

See Subsection 8.3.4.9 for COL license information.

8.3.1.0 Non-Class 1E AC Power System

8.3.1.0.1 Non-Class 1E Medium Voltage Power Distribution System

The non-Class 1E medium voltage power distribution system consists of four 13.8 kV power generation buses and three 4.16 kV plant investment protection buses. The four power generation load group configuration was chosen to meet the requirement that the ten RIPs be powered by four independent buses to minimize large core flow reduction events and to match the mechanical power generation systems that are mostly four trains (e.g., four feedwater pumps, four condensate pumps, four booster pumps, four heater drain pumps, four circulating water pumps). The three plant investment protection load group configuration was chosen to match the mechanical systems that consist of three or two trains.

~~The non-Class 1E medium voltage power distribution system consists of nine 6.9 kV buses divided into three load groups. The three load group configuration was chosen to match the mechanical systems which are mostly three trains (e.g. three feedwater pumps, three circulating water pumps, three turbine building supply and exhaust fans).~~

~~Within each load group there is one~~ The four power generation ~~bus~~ buses which ~~supplies~~ supply power production loads ~~which do not provide water to the pressure vessel~~. Each one of these buses has access to power from one winding of its assigned unit auxiliary transformer. ~~It also has~~ They also have access to the reserve auxiliary transformer or CTG as an alternate source ~~if its unit~~ , if their unit auxiliary transformer fails or during maintenance outages for the normal feed. Bus transfer between preferred power sources is manual dead bus transfer and not automatic.

delete paragraph

~~Another power generation bus within each load group supplies power to pumps which are capable of supplying water to the pressure vessel during normal power operation (i.e., the condensate and feedwater pumps). These buses normally receive power from the unit auxiliary transformer and supply power to the third bus [plant investment protection (PIP)] in the load group through a cross tie. The cross tie automatically opens on loss of power but may be manually re-closed if it is desired to operate a condensate and feedwater pump or a condensate pump from the reserve auxiliary transformer which is connectable to the PIP buses. In addition, the combustion turbine generator is capable of supplying power to any of the condensate pumps through the bus ties from the PIP buses. This provides three load groups of non safety grade equipment, in addition to the divisional Class 1E load groups, which may be used to supply water to the reactor vessel in emergencies.~~

Each of the three load groups has its own ~~A third~~ Plant Investment Protection (PIP) bus which supplies power to non-safety loads (e.g. the turbine building HVAC, the turbine building service water and the turbine building closed cooling water systems). On loss of normal or alternate preferred power, pre-selected buses are automatically transferred ~~the cross tie to the power generation bus is automatically tripped open and the non Class 1E PIP bus is automatically transferred (two out of the three buses in the load groups transfer)~~ via a dead bus transfer to the combustion turbine which automatically starts on loss of power. The PIP systems for each selected load group automatically restart to support their ~~load groups.~~ loads.

The non-Class 1E and the Class 1E switchgear interrupting ratings are chosen to be capable of clearing maximum expected fault current. The steady state ratings are chosen to carry the maximum expected normal currents. The 13.8 kV/4.16 kV switchgear is respectively rated at 15 kV/4.76kV

~~The non Class 1E buses are comprised of metal clad switchgear rated for 7.2 kV 500 MVA with a bus full load rating of 2000A. Maximum calculated full load short time current is 1700A. Bus ratings of 3000A are available for the switchgear as insurance against future load growth, if necessary. The circuit breaker interrupting capacity is 41,000 amperes. Instrument and control power is from the non Class 1E, 125VDC power system.~~

13.8

The ~~6.9~~ kV buses supply power to adjustable speed drives for the feedwater and reactor internal pumps. These adjustable speed drives are designed to the requirements of IEEE-519. Voltage distortion limits are as stated in Table 4 of the IEEE Std.

13.8 kV and 4.16 kV

device

Each ~~6.9~~ kV bus has a safety grounding ~~circuit breaker~~ designed to protect personnel during maintenance operations (see Figure 8.3-1). During periods when the buses are energized, these ~~breakers~~ are racked out (i.e., in the disconnect position). A control room ~~annunciator sounds~~ whenever any of these ~~breakers~~ are racked for service. The interlocks for the bus grounding devices are as follows:

devices

alarm is generated

devices

out

(1) Under-voltage relays must be actuated.

(2) Bus Feeder breakers must be in the disconnect position.

(3) Voltage for bus instrumentation must be available.

devices

Conversely, the bus feeder breakers are interlocked such that they cannot close unless their associated grounding ~~breakers~~ are in their disconnect positions.

8.3.1.0.2 Non-Class 1E Low Voltage Power Distribution System

8.3.1.0.2.1 Power Centers

4.16

There are two double-ended, and at least two single-ended power centers on each of the PIP buses.

Power for the non-Class 1E 480V auxiliaries is supplied from power centers consisting of ~~6.9~~ kV/480V transformers and associated metal-clad switchgear (see Figure 8.3-1). ~~There are six non Class 1E, (two per load group), power centers. One power center per load group is supplied power from the non-Class 1E PIP bus in the load group.~~

Non-Class 1E 480V power centers supplying non-Class 1E loads are arranged as independent radial systems, with each 480V bus fed by its own power transformer.

The 480V power centers are sized to supply motor control centers and motor loads greater than 100 kW, and up to and including 300kW. Switchgear for the 480V load centers is of indoor, metal-enclosed type with draw-out circuit breakers which will interrupt maximum fault currents. Control power is from the non-Class 1E 125 VDC power system of the same non-Class 1E load group.

8.3.1.0.2.2 Motor Control Centers

The non-Class 1E 480V MCCs are sized to supply motors 100kW or smaller, control power transformers, process heaters, motor-operated valves and other small electrically operated auxiliaries, including 480-120V and 480-240V transformers. Non-Class 1E motor control centers are located in proximity to their loads.

Starters for the control of 460V motors 100kW or smaller are MCC-mounted, across-the-line magnetically operated, air break type. Power circuits entering into the containment

IEEE 141 and/or other acceptable industry standards or practices to determine fault currents.

Power center transformers are sized and impedances chosen to facilitate the selection of low-voltage switchgear, MCCs and distribution panels, which are optimized within the manufacturer's recommended ratings for interrupting capacity and coordination of over-current devices. Impedance of connecting upstream cable is factored in for a specific physical layout.

8.3.1.0.6 Circuit Protection

8.3.1.0.6.1 Philosophy of Protection

Simplicity of load grouping facilitates the use of conventional, protective relaying practices for isolation of faults. Emphasis has been placed in preserving function and limiting loss of equipment function in situations of power loss or equipment failure.

Breaker coordinates analysis will be performed in accordance with IEEE 141, 242 and/or other acceptable industry standards or practices.

Circuit protection of the non-Class 1E buses is interfaced with the design of the overall protection system.

8.3.1.0.6.2 Grounding Methods

delete text

Station grounding and surge protection is discussed in Section 8A.1. The medium voltage ~~(6.9kV)~~ system is low resistance grounded except that the combustion turbine generator is high resistance grounded to maximize availability.

See Subsection 8.3.4.14 for COL license information pertaining to administrative control for bus grounding circuit ~~breakers~~. devices.

8.3.1.0.6.3 Bus Protection

Bus protection is as follows:

Medium voltage

(1) ~~6.9kV~~ bus incoming circuits have inverse time over-current, ground fault, bus differential and under-voltage protection.

(2) ~~6.9kV~~ feeders for power centers have instantaneous, inverse time over-current and ground fault protection.

(3) ~~6.9kV feeders for heat exchanger building substations have inverse time over-current and ground fault protection.~~ Not used.

(4) ~~6.9kV~~ feeders used for motor starters have instantaneous, inverse time over-current, ground fault protection.

(5) 480V bus incoming line and feeder circuits have inverse time over-current and ground fault protection.

8.3.1.1 Class 1E AC Power Distribution System

8.3.1.1.1 Medium Voltage Class 1E Power Distribution System

4.16 Class 1E AC power loads are divided into three divisions (Divisions I, II, and III), each fed from an independent ~~6.9~~ kV Class 1E bus. During normal operation (which includes all modes of plant operation; i.e., shutdown, refueling, startup, and run), two of the three divisions are normally fed from an offsite normal preferred power supply. The remaining division is normally fed from the alternate preferred power source (Subsection 8.3.4.9).

The Class 1E buses are comprised of metal clad switchgear with normal and interrupting ratings approximately sized to carry normal loads and clear expected faults. Instrument and control power is from the Class 1E 125 VDC power systems in the same Class 1E division.

~~The Class 1E buses are comprised of metal clad switchgear rated for 7.2kV 500MV-A with a bus full load rating of 2,000 amperes. Maximum calculated full load short time current is 1,700 amperes. Bus ratings of 3,000 amperes are available for the switchgear as insurance against further load growth, if necessary. The circuit breaker interrupting capacity is 41,000 amperes. Instrument and control power is from the Class 1E 125VDC power system in the same Class 1E division.~~

4.16 Each ~~6.9~~ kV bus has a safety grounding circuit ~~breaker~~ device designed to protect personnel during maintenance operations (see Figure 8.3-1). During periods when the buses are energized, these ~~breakers~~ devices are racked out (i.e., in the disconnect position). A control room annunciator sounds whenever any of these ~~breakers~~ devices are racked in for service.

The interlocks for the bus grounding devices are as follows:

(1) Under-voltage relays must be actuated.

(2) Bus Feeder breakers must be in the disconnect position.

(3) Voltage for bus instrumentation must be available.

Conversely, the bus feeder breakers are interlocked such that they cannot close unless their associated grounding breakers are in their disconnect positions.

Standby AC power for Class 1E buses is supplied by diesel generators at ~~6.9~~ 4.16 kV and distributed by the Class 1E power distribution system. Division I, II and III buses are automatically transferred to the diesel generators when the preferred power supply to these buses is ≤ 70% bus voltage.

The Division I Class 1E bus supplies power to three separate groups of non-Class 1E fine motion control rod drive (FMCRD) motors (see Figure 8.3-1, sheet 3). Although these motors are not Class 1E, the drives may be inserted as a backup to scram and are of special importance because of this. It is important that the first available standby power be available for the motors, therefore, a diesel supplied bus was chosen as the first

source of standby AC power and a combustion turbine supplied PIP bus as the second backup source. Division I was chosen because it was the most lightly loaded diesel generator.

The load breakers in the Division I switchgear are part of the isolation scheme between the Class 1E power and the non-Class 1E load. In addition to the normal over-current tripping of these load breakers, Class 1E zone selective interlocking is provided between them and the upstream Class 1E bus feed breakers.

If fault current flows in the non-Class 1E load, it is sensed by Class 1E micro-processor controlled protective relaying equipment. This equipment utilizes digital timers that can reproduce the timing requirements by sensing the number of cycles of the electrical waveform itself. This definite time delay is coordinated with that of the upstream bus feeder breakers such that the fault current is terminated before the feeder breakers are free to trip. The tripping of the Class 1E feed breaker is normal for faults which occur on the Class 1E bus it feeds.

~~If fault current flows in the non-Class 1E load, it is sensed by the Class 1E current device for the load breaker and a trip blocking signal is sent to the upstream Class 1E feed breakers. This blocking lasts for about 75 milliseconds. This allows the load breaker to trip in its normal instantaneous tripping time of 35 to 50 milliseconds, if the magnitude of the fault current is high enough. This assures that the fault current has been terminated before the Class 1E upstream breakers are free to trip. For fault currents of lesser magnitude, the blocking delay will time out without either bus feeder or load breakers tripping, but the load breaker will eventually trip and always before the upstream feeder breaker. This order of tripping is assured by the coordination between the breakers provided by long time pickup, long time delay and instantaneous pickup trip device characteristics. Tripping of the Class 1E feed breaker is normal for faults which occur on the Class 1E bus it feeds. Coordination is provided between the bus main feed breakers and the load breakers.~~

The fault interrupt capability of all Class 1E breakers, fault interrupt coordination between the supply and load breakers for each Class 1E load and the Division I non-Class 1E load, and the zone selective interlock feature of the breaker for the non-Class 1E load all have the capability of being tested (Subsection 8.3.4.29). The zone selective interlock is a feature of the trip unit for the breaker and is tested when the other features such as current setting and long-time delay are tested.

. The Division I Class 1E bus can be manually connected to a 4.16 kV PIP bus as an alternate collective source of power for the FMCRD load groups.
An isolation between Class 1E bus and non-1E load is maintained per IEEE 384.

Power is supplied to each FMCRD load group from ~~either~~ the Division I Class 1E bus ~~or the non Class 1E PIP bus through a pair of interlocked transfer switches located between the power sources and the 6.9 kV/480V transformer feeding the FMCRD MCC. These transfer switches are classified as associated, and are treated as Class 1E. Switch-over to the non Class 1E PIP bus source is automatic on loss of power from the Class 1E diesel bus source. Switching back to the Class 1E diesel bus power is by manual action only.~~

The design minimizes the probability of a single failure affecting more than one FMCRD group by providing three independent Class 1E feeds (one for each group) directly from the Division I Class 1E ~~6.9~~ kV bus (see sheet 3 of Figure 8.3-1).

4.16

delete paragraph

~~The Class 1E load breakers in conjunction with the zone selective interlocking feature (which is also Class 1E), provide the needed isolation between the Class 1E bus and the~~

delete paragraph (cont'd)

~~non Class 1E loads. The feeder circuits on the upstream side of the Class 1E load breakers are Class 1E. The FMCRD circuits on the load side of the Class 1E load breakers down to and including the transfer switches are associated. Control power for the transfer switches is provided from Division I. The feeder circuits from the non Class 1E PIP bus to the transfer switch, and circuits downstream of the transfer switch, are non Class 1E.~~

Each FMCRD power train has current limiting features to limit the FMCRD motor fault current. Continuous operation of the FMCRD motors at the limiting fault current will not degrade operation of any Class 1E loads. Also, the Division I diesel generator has sufficient capacity margin to supply continuous overload currents up to the trip setpoint of the Class 1E feeder breaker to the FMCRDs.

Non-Class 1E loads being supplied from a Class 1E bus exists only in Division I, as described above for the FMCRDs. Except for associated AC standby and associated DC emergency lighting circuits, non-Class 1E loads are not permitted on Divisions II or III. This prevents any possibility of interconnection between Class 1E divisions.

8.3.1.1.2 Low Voltage Class 1E Power Distribution System

8.3.1.1.2.1 Power Centers

Power for 480V auxiliaries is supplied from power centers consisting of ~~6.9~~ 4.16 kV/480V transformers and associated metal clad switchgear (see Figure 8.3-1). There are at least two power centers in each Class 1E division.

Class 1E 480V power centers supplying Class 1E loads are arranged as independent radial systems, with each 480V bus fed by its own power transformer. Each 480V Class 1E bus in a division is physically and electrically independent of the other 480V buses in other divisions and non-Class 1E load groups.

The 480V power centers are sized to supply motor control centers and motor loads greater than 100 kW, and up to and including 300 kW. Switchgear for the 480V power centers is of indoor, metal-enclosed type with draw-out circuit breakers which will interrupt maximum fault currents. Control power is from the Class 1E 125 VDC power system of the same Class 1E division.

Power centers are located in their respective divisional equipment areas.

8.3.1.1.2.2 Motor Control Centers

The Class 1E 480V MCCs are sized to supply motors 100 kW or smaller, control power transformers, process heaters, motor-operated valves and other small electrically operated auxiliaries, including 480-120V and 480-240V transformers. Class 1E motor

8.3.1.1.5 Class 1E Electric Equipment Considerations

The following guidelines are utilized for Class 1E equipment.

(1) Motors are sized in accordance with NEMA standards. The manufacturers' ratings are at least large enough to produce the starting, pull-in and driving torque needed for the particular application, with due consideration for capabilities of the power sources. Plant design specifications for electrical equipment require such equipment be capable of continuous operation for voltage fluctuations of ±10%. In addition, Class 1E motors must be able to withstand voltage drops to 70% rated during starting transients.

(2) Power sources, distribution equipment and branch circuits are designed to maintain voltage and frequency within acceptable limits. Load and voltage drop analyses will be performed from the source to the utilization equipment in accordance with IEEE-141, 242 and/or other acceptable industry standards or practices to assure that power sources and distribution equipment will be capable of transmitting sufficient energy to start and operate all required loads for all designed plant conditions.

(3) The selection of motor insulation such as Class F, H or B is a design consideration based on service requirements and environment. The Class 1E motors are qualified by tests in accordance with IEEE-334.

(4) Capacity of switchgear, power centers with their respective transformers, motor control centers, and distribution panels is equal to or greater than the maximum available fault current to which it is exposed under all design modes of operation until the fault is cleared.

Interrupting capability of the Class 1E switchgear and MCC breakers is selected to interrupt the available short-circuit current at the circuit breaker load terminals. Short circuit analysis will be performed in accordance with IEEE 141 and/or other acceptable industry standards or practices to determine fault currents. ~~See Subsection 8.2.3(16) for interface requirement.~~

delete sentence

Power center transformers are sized and impedances chosen to facilitate the selection of low-voltage switchgear, MCCs and distribution panels, which are optimized within the manufacturer's recommended ratings for interrupting capacity and coordination of over-current devices. Impedance of connecting upstream cable is factored in for a specific physical layout.

8.3.1.1.6 Circuit Protection

8.3.1.1.6.1 Philosophy of Protection

Simplicity of load grouping facilitates the use of conventional, protective relaying practices for isolation of faults. Emphasis has been placed on preserving function and limiting loss of Class 1E equipment function in situations of power loss or equipment failure.

Breaker coordination analysis will be performed in accordance with IEEE 141, 242 and/or other acceptable industry standards or practices.

Circuit protection of the Class 1E buses is interfaced with the design of the overall protection system.

8.3.1.1.6.2 Grounding Methods

Station grounding and surge protection is discussed in Section 8A.1. The medium voltage ~~(6.9 kV)~~ system is low resistance grounded except that each diesel generator is high resistance grounded to maximize availability.

See Subsection 8.3.4.14 for COL license information pertaining to administrative devices. control for bus grounding circuit ~~breakers.~~

8.3.1.1.6.3 Bus Protection

Bus protection is as follows:

Medium voltage

(1) ~~6.9~~ kV bus incoming circuits have inverse time over-current, ground fault, bus differential and under-voltage protection.

(2) ~~6.9~~ kV feeders for power centers have instantaneous, inverse time over-current and ground fault protection.

(3) ~~6.9 kV feeders for heat exchanger building substations have inverse time over-current and ground fault protection.~~ Not used.

(4) ~~6.9~~ kV feeders used for motor starters have instantaneous, inverse time over-current, ground fault and motor protection.

(5) 480V bus incoming line and feeder circuits have inverse time over-current and ground fault protection.

8.3.1.1.6.4 Protection Requirements for Diesel Generators

Protective devices of the diesel generators meet all requirements of IEEE-603. When the diesel generators are called upon to operate during LOCA conditions, the only

protective devices which shut down the diesel are the generator differential relays, and the engine over-speed trip. These protection devices are retained under accident conditions to protect against possible, significant damage. Other protective relays, such as loss of excitation, anti-motoring (reverse power), over-current voltage restraint, low jacket water pressure, high jacket water temperature, and low-lube oil pressure, are used to protect the machine when operating in parallel with the offsite power system, during periodic tests. The relays are automatically isolated from the tripping circuits during LOCA conditions when there is a concurrent LOPP signal. However, all of these bypassed parameters are annunciated in the main control room (Subsection 8.3.1.1.8.5). The bypasses and protective relays are testable and meet all IEEE-603 requirements, and are manually reset as required by Position 1.8 of Regulatory Guide 1.9. No trips are bypassed during LOPP or testing. See Subsection 8.3.4.22 for COL license information.

Synchronizing interlocks are provided to prevent incorrect synchronization whenever the diesel generator is required to operate in parallel with the preferred power supply (see Section 5.1.4.2 of IEEE-741). Such interlocks are capable of being tested, and shall be periodically tested per Section 8.3.4.23).

8.3.1.1.7 Load Shedding and Sequencing on Class 1E Buses

4.16 This subsection addresses Class 1E Divisions I, II, and III. Load shedding, bus transfer and sequencing on a ~~6.9~~ kV Class 1E bus is initiated on loss of bus voltage. Only LOPP signals (≤70% bus voltage) or degraded voltage signals are used to trip the loads. However, the presence of a LOCA during LOPP reduces the time delay for initiation of bus transfer from 3 seconds to 0.4 seconds. The Class 1E equipment is designed to sustain operation for this 3-second period without damage to the equipment. The load sequencing for the diesels is given on Table 8.3-4.

Load shedding and bus ready-to-load signals are generated by the under-voltage relays monitoring the Class 1E medium voltage switchgear buses. Individual timer start and reset signals for the LOPP condition are generated, for each major LOPP load, by the bus under-voltage relays. Individual timer start and reset signals for the LOCA condition are generated, for each major LOCA load, by the Safety System Logic and Control (SSLC) system. Table 8.3-4 defines which loads are sequenced onto the diesel generator for the LOPP and LOPP + LOCA conditions. (i.e. if a LOCA signal is not present, only LOPP loads are sequenced).

4.16 (1) **Loss of Preferred Power (LOPP)**—The ~~6.9~~ kV Class 1E buses are normally energized from the normal or alternate preferred power supplies. Should the bus voltage decay to ≤ 70% of its nominal rated value, a bus transfer is initiated and the signal will trip the supply breaker, and start the diesel generator. 4.16 When the bus voltage decays to 30%, large pump motor breakers (~~6.9~~ kV) are tripped. The transfer then proceeds to the diesel generator. If the standby

diesel generator is ready to accept load (i.e., voltage and frequency are within normal limits and no lockout exists, and the normal and alternate preferred supply breakers are open), the diesel-generator breaker is signalled to close, following the tripping of the large motors. This accomplishes automatic transfer of the Class 1E bus to the diesel generator. Motor loads will be sequence started as required and shown on Table 8.3-4.

(2) **Loss of Coolant Accident (LOCA)**—When a LOCA occurs, the standby diesel generator is started and remains in the standby mode (i.e. voltage and frequency are within normal limits and no lockout exists) unless a LOPP signal is also present as discussed in (3) and (4) below. In addition, with or without a LOPP, the load sequence timers are started if the ~~6.9~~ kV emergency bus voltage is greater than 70%, and loads are applied to the bus at the end of preset times. 4.16

Each load has an individual load sequence timer which will start if a LOCA occurs and the ~~6.9~~ kV emergency bus voltage is greater than 70%, regardless of whether the bus voltage source is normal or alternate preferred power or the diesel generator. The load sequence timers are part of the low level circuit logic for each LOCA load and do not provide a means of common mode failure that would render both onsite and offsite power unavailable. If a timer failed, the LOCA load could be applied manually provided the bus voltage is greater than 70%. 4.16

(3) **LOPP following LOCA**—If the bus voltage (normal or alternate preferred power) is lost during post-accident operation, transfer to the diesel generator occurs as described in (1) above.

(4) **LOCA following LOPP**—If a LOCA occurs following loss of the normal or alternate preferred power supplies, the LOCA signal sequences ESF equipment onto the bus as required. Running loads are not tripped. Automatic (LOCA + LOPP) time delayed load sequencing assures that the diesel-generator will not be overloaded.

(5) **LOCA when diesel generator is parallel with preferred power source during test**—If a LOCA occurs when the diesel generator is paralleled with either the normal preferred power or the alternate preferred power source, the D/G will automatically be disconnected from the ~~6.9~~ kV emergency bus regardless of whether the test is being conducted from the local control panel or the main control room. 4.16

(6) **LOPP during diesel generator paralleling test**—If the normal preferred power supply is lost during the diesel-generator paralleling test, the diesel-generator circuit breaker is automatically tripped. Transfer to the diesel generator then proceeds as described in (1).

If the alternate preferred source is used for load testing the diesel generator, and the alternate preferred source is lost, the diesel-generator breaker is automatically tripped. Load shedding and bus transfer will proceed as described in (1).

(7) **Restoration of offsite power**—Upon restoration of offsite power, the Class 1E bus(es) can be transferred back to the offsite source by manual operation only.

(8) **Protection against degraded voltage**—For protection of the Division I, II and III electrical equipment against the effects of a sustained degraded voltage, the ~~6.9~~ kV divisional bus voltages are monitored. If the bus voltage increases to 110% of its rated value, the over-voltage will be annunciated in the control room. If the bus voltage degrades to 90% (or below) of its rated value, and after a time delay (to prevent triggering by transients), under-voltage will be annunciated in the control room. Simultaneously, a protective relay timer is started to allow the operator to take corrective action. The timer settings are based on the system load analysis* such that the respective feeder breaker trips, which consequently starts the diesel generator, before any of the Class 1E loads experience degraded conditions exceeding those for which the equipment is qualified. This assures such loads will restart when the diesel generator assumes the degraded bus and sequences its loads. If the bus voltage recovers within the time delay period, the protective timer will reset. Should a LOCA occur during the time delay, or if the degraded voltage condition reaches 70% bus voltage, the feeder breaker with the under-voltage will be tripped instantly. Subsequent bus transfer will be as described above. These bus voltage monitoring schemes are designed in accordance with Section 5.1.2 of IEEE-741.

4.16

Equipment is qualified for continuous operation with voltage ±10% of nominal and for degraded voltages below 90% for the time period established in the load analysis* for the degraded voltage protective time delay relay. (See 8.3.4.20 for COL license information.)

* Load analyses will be performed in accordance with IEEE-141, IEEE-242 and/or other acceptable industry standards or practices, for the power distribution system to demonstrate proper sizing of power source and distribution equipment. Such analyses will provide the basis for the degraded voltage protective relay timer settings and other protective relay settings.

(9) **Station Blackout (SBO) considerations**—A station blackout event is defined as the total loss of all offsite (preferred) and onsite Class IE AC power supplies except Class IE AC power generated through inverters from the station batteries. In such an event, the combustion turbine generator (CTG) will automatically start and achieve rated speed and voltage ~~within two~~ in less than ten minutes. The CTG will then automatically assume pre-selected loads on the plant investment protection (PIP) buses. With the diesel generators unavailable, the reactor operator will manually shed PIP loads and connect the non-Class 1E CTG with the required shutdown loads within ten minutes of the event initiation. Specifically, the operator will energize one of the Class 1E distribution system buses by closing each of the ~~two~~ circuit breakers (via controls in the main control room) between the CTG unit and the Class 1E bus. The ~~circuit breaker closest to the CTG is non-Class 1E and the~~ circuit breaker closest to the Class 1E bus is Class 1E, and the other breakers are non-Class 1E. Later, the operator will energize other safety-related and non-safety-related loads, as appropriate, to complete the shutdown process. See Appendix 1C and Subsection 9.5.11 for further information on Station Blackout and the CTG, respectively.

8.3.1.1.8 Standby AC Power System

The diesel generators comprising the Divisions I, II and III standby AC power supplies are designed to quickly restore power to their respective Class 1E distribution system divisions as required to achieve safe shutdown of the plant and/or to mitigate the consequences of a LOCA in the event of a LOPP. Figure 8.3-1 shows the interconnections between the preferred power supplies and the Divisions I, II and III diesel-generator standby power supplies.

See Subsection ~~9.5.13.8~~ 8.1.4.1 and 8.3.4.2 for COL license information.

8.3.1.1.8.1 Redundant Standby AC Power Supplies

Each standby power system division, including the diesel generator, its auxiliary systems and the distribution of power to various Class 1E loads through the ~~6.9~~ 4.16 kV and 480V systems, is segregated and separated from the other divisions. No automatic interconnection is provided between the Class 1E divisions. Each diesel generator set is operated independently of the other sets and is connected to the offsite transmission network by manual control only during testing or for bus transfer (see Subsection 8.3.4.21 for COL license information). Each diesel generator and its auxiliary systems are classified Seismic Category I.

8.3.1.1.8.2 Ratings and Capability

The size of each of the diesel-generators serving Divisions I, II and III satisfies the requirements of NRC Regulatory Guide 1.9 and IEEE-387 and conforms to the following criteria:

(1) Each diesel generator is capable of starting, accelerating and supplying its loads in the sequence shown in Table 8.3-4.

(2) Each diesel generator is capable of starting, accelerating and supplying its loads in their proper sequence without exceeding a 25% voltage drop or a 5% frequency drop measured at the bus.

(3) Each diesel generator is capable of starting, accelerating and running its largest motor at any time after the automatic loading sequence is completed, assuming that the motor had failed to start initially.

(4) Each diesel generator is capable of reaching full speed and voltage within 20 seconds after receiving a signal to start, and is capable of being fully loaded within the next 65 seconds as shown in Table 8.3-4. The limiting condition is for the RHR and HPCF injection valves to be open 36 seconds after the receipt of a high drywell or low reactor vessel level signal. Since the motor operated valves are not tripped off the buses, they start to open, if requested to do so by their controls, when power is restored to the bus at 20 seconds. This gives them an allowable travel time of 16 seconds, which is attainable for the valves.

See Subsection 8.3.4.2 for COL license information.

9 (5) Each diesel generator is sized to supply its post accident (LOCA) load requirements, and has a continuous load rating of ~~6.25~~MV·A @ 0.8 power factor (Figure 8.3-1). The overload rating is 110% of the rated output for a two-hour period out of a 24-hour period. A load profile analysis for each diesel generator will be performed in accordance with acceptable industry standards and/or practices.

(6) Each diesel generator has stored energy (fuel) at the site in its own storage tank with the capacity to operate the standby diesel generator power supply, while supplying post-accident load requirements to a unit for seven days (Subsection 9.5.4.1.1).

(7) Each diesel generator has stored energy (fuel) at the site in its own day tank with the capacity to operate the standby diesel generator power supply while supplying its maximum LOCA load demand for 8 hours. The fuel transfer system automatically maintains the capacity of the day tank (Subsection 9.5.4.2).

(8) Each diesel generator is capable of operating in its service environment during and after any design basis event, without support from the preferred power supply. It can start up and run, with no cooling available, for the time required to bring the cooling equipment into service as it sequences onto the bus (see Subsection 20.3.6, Question/Answer 430.282).

(9) Each diesel generator is capable of restarting with an initial engine temperature equal to the continuous rating full load engine temperature.

(10) Each diesel generator is capable of accepting design load following operation at light or no load for a period of 4 hours. This capability will be demonstrated by the supplier prior to shipment, but is exempt from periodic testing to avoid undue stress to the diesel engine.

(11) Each diesel generator is capable of carrying its continuous load rating for 22 hours following 2 hours of operation at its short time rating.

(12) The maximum loads expected to occur for each division (according to nameplate ratings) do not exceed 90% of the continuous power output rating of the diesel generator.

(13) Each diesel generator's air receiver tanks have capacity for sufficient starts without recharging as defined in Subsection 9.5.6.2.

(14) During diesel generator load sequencing, the frequency will be restored to within 2% of nominal, and voltage will be restored to within 10% of nominal within 60% of each load sequence time interval (see Position 1.4 of Regulatory Guide 1.9).

(15) During recovery from transients caused by step load increases or resulting from the disconnection of the largest single load, the speed of the diesel generator unit will not exceed the nominal speed plus 75% of the difference between nominal speed and the over-speed trip setpoint or 115% of nominal, whichever is lower (see Position 1.4 of Regulatory Guide 1.9).

(16) The transient following the complete loss of load will not cause the speed of the diesel generator unit to attain the over-speed trip setpoint (see Position 1.4 of Regulatory Guide 1.9).

4.16

(17) Bus voltage and frequency will recover to ~~6.9~~ kV±10% at 60±2% Hz within 10 seconds following trip and restart of the largest load.

(18) Bus voltage and frequency regulation will assure an operating voltage and frequency at the terminals of the Class 1E utilization equipment that is within the utilization equipment tolerance limits.

(d) RG 1.47—Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

(e) RG 1.63—Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants

(f) RG 1.75—Physical Independence of Electric Systems

Regarding Position C-1 of Regulatory Guide 1.75 (Subsection 8.3.1.1.1), the non-Class 1E FMCRD motors are supplied power from the Division 1 Class 1E bus through three dedicated power center transformers. The Class 1E load breaker for the bus is tripped by fault current for faults in the non-Class 1E load. There is also a zone selective interlock provided from the load breaker to the Class 1E bus supply breaker so that the supply breaker is delayed from tripping while fault current is flowing in the non-Class 1E load feeder. This meets the intent of the Regulatory Guide position in that the main supply breaker is prevented from tripping on faults in the non-safety-related loads. The transfer switch downstream of the load feeder is associated, and meets Class 1E requirements.

4.16

There are three ~~6.9~~ kV electrical divisions which are independent load groups backed by individual diesel-generator sets. The low voltage AC systems consists of four divisions which are backed by independent DC battery, charger and inverter systems.

There is no sharing of standby power system components between divisions, and there is no sharing of diesel-generator power sources between units, since the ABWR is a single-unit plant design.

Each standby power supply for each of the three divisions is composed of a single generator driven by a diesel engine having fast start characteristics and sized in accordance with Regulatory Guide 1.9.

Table 8.3-1 and 8.3-2 show the rating of each of the Divisions I, II and III diesel generators, respectively, and the maximum coincidental load for each.

(g) RG 1.106—Thermal Overload Protection for Electric Motors on Motor-Operated Valves

Safety functions which are required to go to completion for safety have their thermal overload protection devices in force during normal plant operation but the overloads are bypassed under accident conditions per Regulatory Position 1.(b) of the guide. These overloads and the

Either the reserve or unit auxiliary transformers are capable of supplying the entire plant normal operating loads. The interconnection capability for the ABWR is such that any non-safety power generation loads can be manually connected to receive power from any of the two sources (i.e., the two switching stations represented by the UATs and RATs). Any plant investment protection load can be manually connected to receive power from three sources (i.e., two switching stations and the CTG). Any class 1E safety bus can be manually connected to receive power from four sources (i.e., two switching stations, the CTG, and the EDGs). Either the UATs or either of the RATs can supply the three class 1E safety buses. Administrative controls are provided to prevent paralleling of sources (Subsection 8.3.4.15). The ABWR therefore exceeds the requirements of the policy issue.

ability to bring the plant to a stable shutdown condition, following a loss of the normal power supply and plant trip." (Quote from EPRI Evolutionary SER, Section 4.2.1, Page 11.4-4, May 1992.)

~~The ABWR reserve auxiliary transformer has the same rating as the three unit auxiliary transformers, and therefore can assume the full load of any one unit auxiliary transformer (Subsection 8.2.1.2). The interconnection capability for the ABWR is such that any plant loads can be manually connected to receive power from any of the six sources (i.e., the two switching stations, the combustion turbine, and the three diesel generators). Administrative controls are provided to prevent paralleling of sources (Subsection 8.3.4.15). The ABWR therefore exceeds the requirements of the policy issue.~~

(5) Other Criteria

(a) IEEE-741—"Standard Criteria for the Protection of Class 1E Power Systems and Equipment in Nuclear Power Generating Stations"

The ABWR fully meets the requirements of this standard.

8.3.2 DC Power Systems

8.3.2.1 Description

8.3.2.1.1 General Systems

A DC power system is provided for switchgear control, control power, instrumentation, critical motors and emergency lighting in control rooms, switchgear rooms and fuel handling areas. Four independent Class 1E 125 VDC divisions, three independent non-Class 1E 125 VDC load groups and one non-Class 1E 250 VDC computer and motor power supply are provided. See Figures 8.3-4 for the single lines.

Each battery is separately housed in a ventilated room apart from its charger and distribution panels. Each battery feeds a DC distribution switchgear panel which in turn feeds local distribution panels and, where required, DC motor control centers. An emergency eye wash is supplied in each battery room.

All batteries are sized so that designed loads will not exceed warranted capacity at end-of-installed-life with 100% design demand.

8.3.2.1.1.1 Class 1E 125 VDC System

The 125 VDC system provides a reliable control and switching power source for the Class 1E systems.

(9) Bases the first minute of the batteries' duty cycle on the sum of all momentary, continuous, and non-continuous loads that can be expected to operate during the one minute following a LOCA and/or LOPP

(10) Is designed so that each battery's capacity can periodically be verified

The battery output breaker has an over-current trip and interrupts fault current flow from the battery to a bus fault. A combination disconnect switch and fuse is an acceptable alternate for the battery output breaker. The charger output breaker is used as a disconnect switch only, because the charger is load limiting and therefore protects itself. Bus load breakers have over-current trips coordinated with the battery output breaker. Fault current necessary to trip the load breakers is supplied by the battery because the battery charger is load limiting.

The batteries are installed in accordance with industry recommended practice as defined in IEEE-484, and meet the recommendations of Section 5 of IEEE-946 (Subsection 8.3.4.32).

8.3.2.1.2 Class 1E DC Loads

4.16 The 125 VDC Class 1E power is required for emergency lighting, diesel-generator field flashing, control and switching functions such as the control of ~~6.9~~ kV and 480V switchgear, control relays, meters and indicators, multiplexers, vital AC power supplies, as well as DC components used in the reactor core isolation cooling system.

The four divisions that are essential to the safe shutdown of the reactor are supplied from four independent Class 1E 125 VDC buses.

8.3.2.1.3 Class 1E Station Batteries and Battery Chargers, General Considerations

The four ESF divisions are supplied from four independent Class 1E 125 VDC systems (Figure 8.3-4). Each of the Class 1E 125 VDC systems has a 125 VDC battery, a battery charger and a distribution panel. One standby battery charger can be connected to either of two divisions and another standby battery charger can be connected to either of two other divisions. Kirk key interlocks prevent cross connection between divisions. The main DC distribution buses include distribution panels, drawout-type breakers and molded case circuit breakers.

The Class 1E 125 VDC systems supply DC power to Divisions I, II, III and IV, respectively, and are designed as Class 1E equipment in accordance with IEEE-308. They are designed so that no single failure in any 125 VDC system will result in conditions that prevent safe shutdown of the plant with the remaining AC power divisions. The plant design and circuit layout from these DC systems provide physical separation of the equipment, cabling and instrumentation essential to plant safety.

(6) Breaker coordination analyses will be performed in accordance with IEEE 141, 242, and/or other acceptable industry standards or practices.

delete sentence

~~See Subsection 8.3.4.6 for COL license information.~~

8.3.2.1.3.2 Non-Class 1E 125 VDC System

A non-class 1E 125 VDC power supply, Figure 8.3-4, is provided for non-Class 1E switchgear, valves, converters, transducers, controls and instrumentation. The system has three load groups with one battery, charger and bus per load group. There are bus tie breakers between buses. Normal operation is with bus tie breakers open and interlocks prevent paralleling batteries. Each load group's battery and charger may be removed from service as a unit for maintenance or testing. A battery can be recharged by its charger prior to being placed back into service.

One backup charger is provided and is connectable to any of the three buses, one bus at a time, under control of Kirk key interlocks to:

(1) Perform extended maintenance on the normal charger for the load group.

(2) To make a live transfer of a bus to supply power from the bus of another load group without paralleling the two batteries.

The chargers are load limiting battery replacement type chargers capable of operation without a battery connected to the bus. The backup charger may be supplied from the AC supply of any one of the three non-Class 1E load groups. It may be used to charge any one battery at a given time. For example the load Group B battery may be charged from load Groups A or B or C AC power via the backup charger.

Each bus is connectable to either of the other two buses via Kirk key interlocked tie breakers. The Kirk key interlock system allows paralleling of chargers. Since the chargers are self load limiting, parallel operation is acceptable. The Kirk key interlock system prevents parallel operation of batteries. This is to prevent the possibility of paralleling batteries which have different terminal voltages and experiencing a large circulating current as a result.

The battery output breaker has an over-current trip and interrupts fault current flow from the battery to a bus fault. A combination disconnect switch and fuse is an acceptable alternate for the battery output breaker. The charger output breaker is used as a disconnect switch only, because the charger is load limiting and therefore protects itself. Bus load breakers have over-current trips coordinated with the battery output breaker. Tripping current for the load breakers is supplied by the battery.

discernible. Exceptions are permitted for individual conductors within cabinets or panels where all wiring is unique to a single division. Any non-divisional cable within such cabinets shall be appropriately marked to distinguish it from the divisional cables.

8.3.3.5.1.3 Raceway Identification

All conduit is tagged with a unique conduit number, in addition to the marking characteristics shown below, at 4.57m intervals, at discontinuities, at pull boxes, at points of entrance and exit of rooms and at origin and destination of equipment.

delete text

Conduits containing cables operating at above 600V ~~(i.e., 6.9 kV)~~ are also tagged to indicate the operating voltage. These markings are applied prior to the installation of the cables.

All Class 1E cable raceways are marked with the division color, and with their proper raceway identification at 4.57m intervals on straight sections, at turning points and at points of entry and exit from enclosed areas. Cable trays are marked prior to installation of their cables.

To help distinguish the neutron-monitoring and scram solenoid cables from other type cables, the following unique voltage class designations and markings are used:

Type of Special Cables	Unique Voltage Class
Neutron-monitoring	VN
Scram solenoid cable	VS

The VN or VS markings are superimposed on the divisional color markings, and placed at the same intervals.

For EMI protection, neutron-monitoring cables are run in their own dedicated divisional conduits and cable trays. Scram solenoid cables are run in a separate conduit for each rod scram group.

The redundant Class 1E, equipment and circuits, assigned to redundant Class 1E divisions and non-Class 1E system equipment and circuits are readily distinguishable from each other without the necessity for consulting reference materials. This is accomplished by color coding of equipment, nameplates, cables and raceways, as described above.

8.3.3.5.1.4 Sensory Equipment Grouping and Designation Letters

Redundant sensory logic/control and actuation equipment for safety-related systems shall be identified by suffix letters. Sensing lines are discussed in Subsection 7.7.1.1.

8.3.3.6 Independence of Redundant Systems

8.3.3.6.1 Power Systems

The Class 1E onsite electric power systems and major components of the separate power divisions are shown on Figure 8.3-1.

Independence of the electric equipment and raceway systems between the different divisions is maintained primarily by firewall-type separation as described in Subsection 8.3.3.6.2. Any exceptions are justified in Appendix 9A, Subsection 9A.5.5.5.

The physical independence of electric power systems complies with the requirements of IEEE-384, General Design Criteria 17, 18 and 21 and NRC Regulatory Guides 1.6 and 1.75.

8.3.3.6.1.1 Class 1E Electric Equipment Arrangement

(1) Class 1E electric equipment and wiring is segregated into separate divisions so that no single credible event is capable of disabling enough equipment to hinder reactor shutdown and removal of decay heat by either of two unaffected divisional load groups or prevent isolation of the containment in the event of an accident. Separation requirements are applied to control power and motive power for all systems involved.

(2) Equipment arrangement and/or protective barriers are provided such that no locally generated force or missile can destroy any RPS, NSSS, ECCS, or ESF functions. In addition, arrangement and/or separation barriers are provided to ensure that such disturbances do not affect both HPCF and RCIC systems.

(3) Routing of wiring/cabling is arranged such as to eliminate, insofar as practical, all potential for fire damage to cables and to separate the redundant divisions so that fire in one division will not propagate to another division. Class 1E and non-Class 1E cables are separated in accordance with IEEE-384 and R.G. 1.75, as explained in 8.3.3.1. This includes cables within cable chases. (Figures 9A.4-1 through 9A.4-16).

(4) An independent raceway system is provided for each division of the Class 1E electric system. The raceways are arranged, physically, top to bottom, as follows (based on the function and the voltage class of the cables):

(a) V4 = Reserved for non-safety 13.8 kV cables (15 kV rated).

(b) V3 = 4.16 kV safety and non-safety cables (5 kV rated). Safety and non-safety cables are divisionally separated.

~~(a) V4 = Medium voltage power, 6.9 kV (8kv insulation class).~~

~~(b) V3 = Low voltage power including 480 VAC, 120 VAC, 125 VDC power and all instrumentation and control power supply feeders (600V insulation class).~~

(c) V2 = Low voltage power including 480 VAC, 120/208 VAC, 250 VDC, 125 VDC (600V rated).

(d) V1 = DCIS related cables (fiber optics, Ethernet, RS-232, RS-485, contact interrogation, 4-20 mA transducers).

~~(c) V2 = High level signal and control, including 125 VDC and 120 VAC controls which carry less than 20A of current and 250 VDC or AC for relay contactor control.~~

~~(d) V1 = Low level signal and control, including fiber optic cables and metallic cables with analog signals up to 55 VDC and digital signal up to 12 VDC.~~

Power cables (V3) are routed in flexible metallic conduit under the raised floor of the control room. For EMI considerations, power cables are routed in metallic conduit wherever they come in close proximity with low level (V1) cables.

4.16

(5) Class 1E power system power supplies and distribution equipment (including diesel generators, batteries, battery chargers, CVCF power supplies, ~~6.9~~ kV switchgear, 480V load centers, and 480V motor control centers) are located in areas with access doors that are administratively controlled. In addition, AC and DC distribution panels are located in the same or similar areas as Class 1E power supplies and distribution equipment, or the distribution panels are designed to be locked, so that access to circuit breakers located inside such panels can be administratively controlled. The physical design of the ABWR permits the administrative control of access to Class 1E power equipment areas (Subsection 13.6.3). See Subsection 8.3.4.19 for COL license information.

8.3.3.6.1.2 Electric Cable Installation

(1) **Cable de-rating and cable tray fill**—Base ampacity rating of cables is established as described in Subsection 8.3.3.8.1. Electric cables of a discrete Class 1E electric system division are installed in a cable tray system provided for the same division. Cables are installed in trays in accordance with their voltage ratings and as described in Subsection 8.3.3.6.1.1(4). Tray fill is as established in Subsection 8.3.3.8.

(2) **Cable routing in potentially hostile areas**—Circuits of different safety divisions are not routed through the same potentially hostile area, with the exception of main steam line instrumentation and control circuits and main steam line isolation valves circuits which are exposed to possible steam line break and turbine missiles, respectively. Cable routing in the drywell is discussed in association with the equipment it serves in the "Special Cases" Section 9A.5.

(3) **Sharing of cable trays**—All divisions of Class 1E AC and DC systems are provided with independent raceway systems.

8.3.4.3 Not Used

8.3.4.4 Protective Devices for Electrical Penetration Assemblies

Appropriate plant procedures shall include periodic testing and calibration of protective devices (except fuses which will be inspected) to demonstrate their functional capability to perform their required safety functions.

8.3.4.5 Not Used

8.3.4.6 Not Used

8.3.4.7 Not Used

8.3.4.8 Not Used

8.3.4.9 Offsite Power Supply Arrangement

The COL applicant operating procedures shall require one of the three divisional buses of Figure 8.3-1 be fed by the alternate power source during normal operation; in order to prevent simultaneous de-energization of all divisional buses on the loss of only one of the offsite power supplies. The selection of that division should be based on the Class 1E bus loads, the reliability/stability of the offsite circuits, and on the separation of the offsite feeds as they pass through the divisional areas.

Continued plant operation will be appropriately limited when the reserve auxiliary transformer is inoperable. See 8.2.4 for COL license information requirements.

8.3.4.10 Not Used

8.3.4.11 Not Used

8.3.4.12 Not Used

8.3.4.13 Load Testing of Class 1E Switchgear and Motor Control Centers

The COL applicant will provide procedures for load testing the Class 1E switchgear and motor control centers by operating connected Class 1E loads at 9% to 10% above, and 9% to 10% below design voltage.

Devices

8.3.4.14 Administrative Controls for Bus Grounding Circuit ~~Breakers~~

devices

Figure 8.3-1 shows bus grounding circuit ~~breakers,~~ which are intended to provide safety grounds during maintenance operations. Administrative controls shall be provided by the COL applicant to keep these circuit ~~breakers~~ racked out (i.e., in the disconnect position) whenever corresponding buses are energized (Subsection 8.3.1.1.6.2).

devices

8.3.4.29 Periodic Testing of Class 1E Circuit Breakers

Appropriate plant procedures shall include periodic calibration and functional testing of the fault interrupt capability of all Class 1E breakers, fault interrupt coordination between the supply and load breakers for each Class 1E load and ~~the~~ Division I non-Class 1E load, and the zone selective interlock feature of ~~the~~ breaker ~~and transfer switch for the~~ non-Class 1E load (Subsection 8.3.1.1.1).

each
each
each

8.3.4.30 Periodic Testing of Electrical Systems & Equipment

Appropriate plant procedures shall include periodic testing of all Class 1E electrical systems and equipment in accordance with Section 7 of IEEE-308.

8.3.4.31 Not Used

8.3.4.32 Class 1E Battery Installation and Maintenance Requirements

The installation, maintenance, testing, and replacement of the Class 1E station batteries shall meet the requirements of IEEE-484 and Section 5 of IEEE-946 (Subsection 8.3.2.1.1.1).

8.3.4.33 Periodic Testing of Class 1E Batteries

Appropriate plant procedures shall include periodic testing of Class 1E batteries, in accordance with Section 7 of IEEE-308, to assure they have sufficient capacity and capability to supply power to their connected loads.

8.3.4.34 Periodic Testing of Class 1E CVCF Power Supplies

Appropriate plant procedures shall include periodic testing of Class 1E constant voltage constant frequency (CVCF) power supplies to assure they have sufficient capacity to supply power to their connected loads (Subsection 8.3.1.1.4.2.1).

8.3.4.35 Periodic Testing of Class 1E Battery Chargers

Appropriate plant procedures shall include periodic testing of Class 1E battery chargers to assure they have sufficient capacity to supply power to their connected loads (Subsection 8.3.2.1.1). Such periodic tests shall be in conformance with Section 7.5.1 of IEEE-308 (i.e., IEEE-338).

8.3.4.36 Periodic Testing of Class 1E Diesel Generators

Appropriate plant procedures shall include periodic testing and/or analysis of Class 1E diesel generators (Subsections 8.3.1.1.8.2, 8.3.1.1.8.3 and 8.3.1.1.8.6), including demonstration of their capability to supply the actual full design basis load current for each sequenced load step.

ANSI C37.50	Test Procedures for Low Voltage AC Power Circuit Breakers Used in Enclosures

Molded Case Circuit Breakers

UL-489	UL Standard for Branch Circuit and Service Circuit Breakers
NEMA AB-1	Molded Case Circuit Breakers

Medium voltage ~~7.2 kV~~ rated metal-clad Switchgear

ANSI C37.01	Application Guide for Power Circuit Breakers
ANSI C37.04	AC Power Circuit Breaker Rating Structure
ANSI C37.06	Preferred Ratings of Power Circuit Breakers
ANSI C37.09	Test Procedure for Power Circuit Breakers
ANSI C37.11	Power Circuit Breaker Control Requirements
ANSI C37.20	Switchgear Assemblies and Metal-Enclosed Bus
ANSI C37.100	Definitions for Power Switchgear
ANSI C37.20	Switchgear Assemblies and Metal-Enclosed Bus
ANSI C37.100	Definitions for Power Switchgear Transformers
ANSI C57.12	General Requirements for Distribution, Power, and Regulating Transformers
ANSI C57.12.11	Guide for Installation of Oil-immersed Transformers (10mV·A and Larger, 69–287 kV rating)
ANSI C57.12.80	Terminology for Power and Distribution Transformers
ANSI C57.12.90	Test Code for Distribution, Power, and Regulating Transformers

See Subsection 8.3.4.17 for COL license information pertaining to common industrial standards referenced in purchase specifications.

Motor-operated isolation valves shall be tested periodically to assure that they are capable of opening or closing by manual switches in the control room and to confirm by observation that the valve position lights on the control panel correctly indicate valve position.

9.5.9.5 Instrumentation Requirements

Operation of the SPCU System is controlled by the plant operator, who may select either of the operational modes of the system or turn it off from the control room.

The containment isolation valves are supplied with position indication in the control room and remote-manual as well as automatic operation.

9.5.10 Motor-Generator Set

9.5.10.1 Design Bases

The primary function of the motor-generator (M-G) set equipment is to provide additional energy storage capacity for extending the coastdown time of the connected reactor internal pumps (RIPs) during a complete loss of AC power bus incident. In normal operation, the MG set converts the incoming electrical power to mechanical energy, then back to electrical power before using it to source the connected loads. By properly sizing the amount of inertia in the MG set for mechanical energy storage, the generator's output can be made less sensitive to large fluctuations in the input power bus voltage. The design bases of the equipment are the following performance criteria:

(1) Following a complete loss of AC power bus input, the operating speed of the connected RIPs shall be maintained, up to the rated speed, for at least one second.

(2) The subsequent speed reduction in the connected RIPs shall not be greater than –10% per second for a minimum period of two seconds.

In addition to meeting the above equipment performance criteria, the MG set is designed to tolerate certain ranges of normal voltage and/or frequency variations in input power source with negligible effect on generator output. These ranges include the normal, continuous variations in bus voltage up to ±10% of rated and in frequency of up to ±5% of rated. Also, fluctuations in bus voltage as caused by the starting or tripping of other large AC machines connecting to the same bus shall be tolerated.

9.5.10.2 System Description

Two MG sets are provided; each is connected to an independent ~~6.9~~ 13.8 kV power bus. The individual power buses are separated from one another by unit auxiliary transformer and circuit breakers. Each MG set is designed to provide constant voltage and constant frequency power to three adjustable speed drives (ASDs). These ASDs are the static

The design bases of the equipment shall meet the following performance criteria:

(1) The CTG unit shall automatically start, accelerate to required speed, reach nominal voltage and frequency, and begin accepting load within ~~two~~ ten minutes of receipt of its start signal.

(2) The CTG shall be capable of being manually connected to SBO shutdown loads (via any one of the Class 1E diesel generator buses) from the main control room within ten minutes from the beginning of the event. The CTG shall also be capable of being manually connected to the remaining Class 1E buses. However, the CTG shall not be normally connected to plant safety buses nor require any external AC power to operate. There shall be two circuit breakers (one Class 1E and one non-class 1E) in series between the CTG and each Class 1E bus.

(3) The reliability of the CTG unit, based on successful starts and successful load runs, shall be ≥ 0.95, as calculated by methods defined in NSAC 108, The Reliability of Emergency Diesel Generators at US Nuclear Power Plants.

(4) The CTG shall have an ISO rating (continuous rating at ~~15°C and at sea level~~ site conditions) of at least ~~9~~ [20] MW, with nominal output voltage of ~~6.9~~ 13.8 kV at 60 Hz.

(5) The generator output shall have a steady-state voltage regulation within 0.5% of required voltage when the load is varied from no load to rated load and all transients have decayed to zero. As a minimum, the CTG shall have sufficient capacity to energize required shutdown loads.

(6) The transient response of the generator shall be capable of assuming sudden application of up to 20% of the generator NEMA rating when the generator, exciter, and regulator are operating at no load, with required voltage and frequency resulting in less than 25% excursion from required voltage. Recovery shall be within 5% of required voltage, with no more than one undershoot or one overshoot within one second.

(7) With the generator initially operating at required voltage, and with a constant load between 0 and 100% at rated power factor, the change in the regulated output shall not exceed 1% of required voltage for any 30-minute period at a constant ambient temperature.

(8) The bus tie arrangement, and the capacity and capability of the CTG, is designed such that the time to place the CTG on line to supply any one load group of safe shutdown loads (i.e., includes manual connection to any one Class 1E bus) shall be within 10 minutes.

(9) The non-Class 1E CTG shall be physically and electrically independent from the Class 1E diesel generators such that weather-related failures, common cause failure, or single-point vulnerabilities are minimized or precluded.

(10) The CTG shall be capable of being periodically inspected, tested and maintained (see Subsection 9.5.13.19 for COL license information).

9.5.11.2 System Description

The interconnections for the CTG are shown on the power distribution system single line diagram (SLD), Figure 8.3-1.

4.16 The CTG is designed to supply standby power to selected loads on any two of the three turbine building (Non-Class 1E) ~~6.9~~ kV buses which carry the plant investment protection (PIP) loads during LOPP events. The CTG automatically starts on detection of a voltage drop of ≤70% on its preselected PIP buses. When the CTG is ready to load, if the voltage level is still deficient, power is automatically transferred to the CTG.

The CTG fuel oil and transfer system is separate from those of the diesel generators.

4.16 Manually controlled breakers also provide the capability of connecting the combustion turbine generator to any of the ~~6.9~~ kV Class 1E buses if all other power sources are lost. The reconfiguration necessary to shed PIP and connect the CTG to a preselected bus for emergency shutdown loads can be accomplished from the main control room within 10 minutes of the onset of a postulated station blackout event. Thus, the CTG meets the requirements for alternate AC (AAC) source (per Regulatory Guide 1.155) such that a station blackout coping analysis is not required. The additional connection capability for the remaining Class 1E buses enable the operator to start and operate redundant shutdown loads and other equipment loads if necessary.

The CTG is provided with a fuel supply that is separate from the fuel supply from the Class 1E onsite AC power system. The fuel shall be sampled and analyzed to maintain quality consistent with standards recommended by the CTG manufacturer.

The CTG is completely independent, and located in a separate building, from the Class 1E AC power sources. Thus, no single-point vulnerability exists between them.

The CTG consists of a completely-packaged, fully-assembled and tested, skid-mounted unit with the following components:

(1) A gas turbine with diesel hydraulic start system (i.e., capable of black start). The unit shall be operated with liquid fuel.

(2) A generator with brushless excitation system and terminal box.

Not used.

(3) ~~A reduction drive gear system between the turbine and generator.~~

(4) Lubrication system.

(5) An oil cooling system.

(6) Accessory gearbox.

(7) Air intake and exhaust equipment.

(8) Microprocessor-based control system with control and protective circuits.

(9) Panels, junction boxes and other accessories as required.

See Appendix 1C for requirements for the CTG oil storage and transfer.

9.5.11.3 Safety Evaluations

The CTG is non-safety-related and its failure will not affect safe shutdown of the plant. The unit is not required for safe shutdown of the plant, but is provided as an alternative AC (ACC) source to mitigate the consequences of a station blackout (SBO) event. The CTG does not supply power to nuclear safety-related equipment except on condition of complete failure of the emergency diesel generators and all offsite power (SBO event). Under this condition, the CTG can provide emergency backup power through manually-actuated breakers in the same manner as the offsite power sources. This provides an alternate AC (AAC) power source in accordance with RG 1.155. Adequate protection of the CTG against sabotage is provided by locating the unit inside the security protected area.

Relative to its function as an AAC source, the CTG complies with Subsection 9.5.14, References 9.5-7, 9.5-8, and 9.5-9.

For detailed assessment of the ABWR during station blackout, see Appendix 1C.

9.5.11.4 Tests and Inspections

The initial test qualification requirements described in IEEE-387, IEEE Standard Criteria for Diesel Units Applied as Standby Power Supplies for Nuclear Power Generating Stations, shall also be applied to the CTG in order to ensure adequate system reliability. However, the factory-test portion of this requirement may be waived if the identically designed unit has been shown capable of maintaining a reliability of 0.99 over a five-year period.

The reliability of the CTG shall meet or exceed 95% as determined in accordance with NSAC-108, or equivalent methodology.

9.5.13.18 Fire-Related Administrative Controls

The COL applicant shall provide the description of the administrative controls outlined in Subsection 9.5.1.6.4.

9.5.13.19 Periodic Testing of Combustion Turbine Generator (CTG)

Appropriate plant operating procedures shall include periodic testing and/or analysis to verify the adequacy of the CTG to meet alternate AC (AAC) requirements for station blackout and to support its use in Section 3.8 of the Technical Specification. As a minimum, such procedures shall verify the following:

4.16

(1) For each ~~6.9~~ Kv emergency bus (staggered among the three buses at 18-month intervals), verify the CTG starts and energizes the bus within 10 minutes and energizes all required loads (as defined in the "LOCA-Loads" section of Table 8.3-4) within 15 minutes. The steady-state CTG voltage and frequency shall be 13.8kV ± 10% and 60 Hz ± 2% ~~≥6210 V and ≤7590 V, and ≥58.8 Hz and ≤61.2 Hz.~~ All CTG starts may be preceded by an engine prelube period.

(2) The operator can accomplish this from the main control room.

(3) ~~One Class 1E circuit breaker and one non Class 1E circuit breaker exist and are functional between each of the Class 1E diesel generator buses and the CTG. (Note that only the circuit breakers for the preselected division are racked in. The remaining two divisions have their Class 1E breakers normally racked out, as shown in Figure 8.3.1.)~~ One Class 1E circuit breaker and four non-Class 1E circuit breakers exist and are functional between each of the Class 1E diesel generator buses and the CTG. (Note that both the Class 1E and non-Class 1E breakers are normally open and they have no automatic function; the operator must manually align the CTG to the diesel generator buses.)

(4) Each 92 days, verify the combustion turbine generator (CTG) starts and achieves steady state voltage (13.8kV ± 10% ~~≥6210 V and ≤7590 V~~), and frequency ~~(≥58.8 Hz and ≤61.2 Hz) within 2~~ (60 Hz ± 2%) in less than 10 minutes. Load the CTG to ≥90% and ≤100% of its continuous rating and operate it with this load for at least 60 minutes. All CTG starts may be preceded by an engine prelube period.

(5) The reliability of the CTG is at least 0.95 as calculated by methods defined in NSAC 108, The Reliability of Emergency Diesel Generators at US Nuclear Power Plants.

9.5.13.20 Operating Procedures for Station Blackout

Appropriate operating procedures and personnel training shall be developed to:

(1) Address the operation of the AAC-CTG during an SBO event

(2) Restore other plant offsite (preferred) and onsite emergency power sources as soon as possible

14.2.12.1.18 Remote Shutdown System Preoperational Test

(1) Purpose

Verify the feasibility and operability of intended remote shutdown functions from the Remote Shutdown System (RSS) panel and other local and remote locations outside the main control room which will be utilized during the remote shutdown scenario.

(2) Prerequisites

The construction tests have been successfully completed, and the SCG has reviewed the test procedure and approved the initiation of testing. Communication shall be established between the RSS panel, main control room, and each system associated with the RSS. Additionally, the 480 VAC and ~~6.9~~ 4.16 kVAC electrical power system shall be in operation and available and 125 VAC/125 VDC control power shall be supplied to the remote shutdown panel. The applicable portions of the RHR, HPCF, RCW, RSW, NBS, ACS, FCS and MUWC shall be available, as needed, to support the specified testing.

(3) General Test Methods and Acceptance Criteria

The Remote Shutdown System (RSS) consists of the control and instrumentation available at the dedicated remote shutdown panel(s) and other local and remote locations intended to be used during the remote shutdown scenario.

Much of the specified testing can be accomplished in conjunction with, or as part of, the individual system and component preoperational testing. However, the successful results of such testing shall be documented as part of this test, as applicable. Performance shall be observed and recorded during a series of individual component and integrated system tests. This test shall demonstrate that the RSS operates properly as specified in Subsection 7.4.1.4 and applicable RSS design specification through the following testing:

(a) Proper functioning of the system controls and instrumentation associated with the RSS after transfer of control to the RSS panel.

(b) Proper operation of remote shutdown system pumps and valves including establishment of system flow paths using RSS control.

(c) Proper functioning of RSS transfer switches including verification of proper override of main control room functions.

14.2.12.1.45.4 Electrical Power Distribution System Preoperational Test

(1) Purpose

To verify the ability of the Electrical Power Distribution System (EPDS) to provide a means for supplying AC power to safety-related and non-safety-related equipment including normal and standby lighting systems, from both onsite and offsite sources, via the appropriate distribution network(s).

(2) Prerequisites

The construction tests for the individual component associated with the EPDS have been successfully completed, and the SCG has reviewed the test procedure and approved the initiation of testing. All the necessary permanently installed and test instrumentation shall have been properly calibrated and operational. Appropriate electrical power sources shall be available for remote control, parameter information and annunciators associated with the electrical power distribution system. Adequate ventilation to both switchgear and battery rooms shall be available and operational. The portion of Fire Protection System covering the EPDS areas shall be available for use. Additionally, the plant EPDS (27 kV, ~~6.9 kV~~, 480V and 120 VAC and 125 VDC power) shall be installed prior to this test.

13.8 kV, 4.16 kV

(3) General Test Methods and Acceptance Criteria

The capability of the non-Class 1E and the Class 1E power system portion of the onsite power system to provide power to plant loads under various plant operating conditions will be demonstrated. The system components to be tested include the medium and low voltage power distribution system, power centers, motor control centers, vital AC power supply system, and instrumentation and control power supply system as appropriate to each portion of the onsite power system. The system performance capability, including actual loading of the DG, is demonstrated in the DG system preoperational test (Subsection 14.2.12.1.45.3).

The ability of the DC power supply system to supply DC power to system loads is demonstrated in the DC power supply system preoperational test (Subsection 14.2.12.1.45.1). This test shall demonstrate that the EPDS operates properly as specified in Subsections 8.2, 8.3, 9.5.3 and 9.5.11 through the following testing:

(a) Proper operation of initiating devices for Class 1E and non Class 1E power system and transfer and trip devices for Class 1E power system.

(b) Proper operation of relaying and logic, including load shedding features for Class 1E power system.

(c) Proper operation of equipment protective devices, including permissive and prohibit interlocks.

this line, fire protection water can be directed to the reactor vessel after the reactor vessel has been depressurized. Fire protection water can also be directed to the drywell spray header to reduce upper drywell pressure and temperature. Should drywell head failure occur (an extremely unlikely event, especially given the containment overpressure protection feature discussed below), use of drywell spray also reduces the release of volatile fission products from the containment.

(b) Combustion Turbine Generator

A combustion turbine generator (CTG) starts automatically. It is automatically loaded with selected investment protection loads. Safety-grade loads can be added manually. This provides diverse power if none of the three safety-grade diesel generators are available.

The CTG is a standby non-safety power source to feed plant investment protection loads during loss-of-offsite power events. It is not seismically qualified. The unit also provides an alternate AC power source in case of a station blackout event.

The CTG is designed to supply standby power to the three turbine building (non-Class 1E) ~~6.9~~ kV buses which carry the plant investment protection loads. The CTG automatically starts on detection of a 30% voltage drop on the ~~6.9~~kV bus. The ~~6.9~~kV bus is tripped and the CTG sequentially assumes the loads. 4.16

CTG failure will not affect safe shutdown of the plant. The unit is not required for safety but is provided to assist in mitigating the consequences of a station blackout event.

The CTG can supply power to nuclear safety-related equipment if there is complete failure of the emergency diesel generators and all offsite power. Under this condition, the CTG can provide emergency backup power through manually-actuated Class-1E breakers in the same manner as the offsite power sources. This provides a diverse source of onsite AC power.

(c) Lower Drywell Flooder

The lower drywell flooder allows water from the suppression pool to enter the lower drywell during severe accidents where core melting and subsequent vessel failure occur. Several pipes run from the vertical pedestal vents into the lower drywell. Each pipe contains a fusible plug valve connected by a flange to the end of the pipe that extends into the lower drywell. In the unlikely event that molten corium flows to the

New criteria relative to factors (1), (3) and (4) above were issued in Branch Technical Position (BTP) PSB-1 "Adequacy of Station Electric Distribution System Voltages", which was incorporated in SRP Section 8.3.1, Appendix A (Reference 19B.2.11-2). Frequency decay [factor (2)] was found not to be a significant safety issue.

Acceptance Criteria

The acceptance criteria for the resolution of USI A-35 is that the design and capability for test and calibration of the undervoltage protection schemes for the Class 1E buses of the onsite power system (while connected to the offsite power source) shall conform to the guidance of BTP PSB-1 in Appendix A of SRP Section 8.3.1.

Specifically, a second level of voltage protection shall be provided for Class 1E equipment in addition to the existing protection based on detecting the complete loss of offsite power to the Class 1E buses. The second level shall have two separate time delays before alerting the control room operator and automatically separating the Class 1E buses from the offsite power source, respectively. Duration of the time delays shall ensure protection from sustained low voltage while avoiding disconnection from the offsite source due to short term transients such as motor starting. The undervoltage protection scheme shall have the capability of being tested and calibrated during power operation. Voltage levels at the safety related buses shall be optimized for the maximum and minimum load conditions that are expected, throughout the anticipated range of offsite power source voltage variation. Technical Specifications are to include limiting conditions of operation, surveillance requirements, and protection equipment setpoints.

Resolution

The conceptual design of an offsite power system and station switchyard(s) for the ABWR design is given in Section 8.2. The interface requirements will ensure that the switchyard(s) provide redundant offsite power feed capability to the nuclear unit, consisting of two preferred power circuits, each capable of supplying the necessary safety loads and other equipment.

4.16 The ABWR onsite power systems are described in Section 8.3, and include three redundant and independent ~~6.9~~kV Class 1E safety buses. The incoming source breakers trip upon loss of normal power, and emergency power is provided to each Class 1E bus by separate and independent diesel generator (DG) units. A combustion turbine generator automatically assumes the plant investment protection loads, but can be used to manually provide back-up power for any Class 1E bus, should a DG fail or be out of service.

The Class 1E AC Power Systems are described in Subsection 8.3.1.1. Protection against degraded voltage is specifically addressed in Subsection 8.3.1.1.7(8). The protection schemes are designed according to the recommendations of IEEE Standard 741 (Reference 19B.2.11-3), which is consistent with the guidance of BTP PSB-1.

Table 3.3.1.4-1 (Page 3 of 5)
ESF Actuation Instrumentation

Function	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	APPLICABLE CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Diesel-Generator Actuation.					
5.a Division I, II, & III Loss of Voltage-6.9 kV. 4.16	1,2,3, 4(h),5(h)	1 per phase(a)	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6	≥ []V and ≤ []V for ≥ [ ] s and ≤ [ ] s
5.b Division I, II, & III Degraded Voltage-6.9 kV. 4.16	1,2,3, 4(h),5(h)	1 per phase(a)	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6	≥ []V and ≤ []V for ≥ [ ] s and ≤ [ ] s
5.c DG System Initiation.	1,2,3 4(h),5(h)	2 per DG(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.5	NA
5.d DG Device Actuation.	1,2,3 4(h),5(h)	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
5.e DG Manual Initiation.	1,2,3, 4(h),5(h)	2 per DG(d)	B, F	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.7	NA
6. Standby Gas Treatment System Actuation.					
6.a SGTS Initiation.	1,2,3 (i)(j)	1 per subsystem(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA
6.b SGTS Device Actuation.	1,2,3 (i)(j)	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
7. Reactor Building Cooling Water/Service Water Actuation.					
7.a RCW/RSW System Initiation.	1, 2, 3, 4(g),5(g)	2 per subsystem(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA
7.b RCW/RSW Device Actuation.	1, 2, 3, 4(g),5(g)	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
7.c RCW/RSW Manual Initiation.	1, 2, 3, 4(g),5(g)	2 per subsystem(d)	B, F	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.7	NA
7.d Division I, II, & III Loss of Voltage-6.9 kV. 4.16	1,2,3, 4(h),5(h)	1 per phase(a)	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6	≥ []V and ≤ []V for ≥ [ ] s and ≤ [ ] s

(Continued)

Table 3.3.1.4-1 (Page 4 of 5)
ESF Actuation Instrumentation

Function	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	APPLICABLE CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7.e Division I, II, & III Degraded Voltage-6/9 kV. 4.16	1,2,3, 4(h),5(h)	1 per phase(a)	C	SR 3.3.1.4.1 SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.5 SR 3.3.1.4.6	≥ []V and ≤ []V for ≥ [ ] s and ≤ [ ] s
8. Containment Atmospheric Monitoring					
8.a CAM System Initiation.	1, 2 ,3	2 per subsystem(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA
8.b CAM Device Actuation.	1, 2, 3	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
9. Suppression Pool Cooling Actuation.					
9.a SPC System Initiation.	1, 2, 3, 4(g),5(g)	2 per subsystem(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA
9.b SPC Device Actuation.	1, 2, 3, 4(g),5(g)	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
9.c SPC Manual Initiation.	1, 2, 3, 4(g),5(g)	2 per subSystem(d)	B, F	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.7	NA
10. Containment Isolation Valves Actuation.					
10.a CIV System Initiation.	1, 2, 3, (i)(j)	2 per division(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA
10.b CIV Device Actuation.	1, 2, 3, (i)(j)	1 per actuated device(c)	D	SR 3.3.1.4.2 SR 3.3.1.4.3 SR 3.3.1.4.4	NA
10.c Drywell Sump Drain LCW Radiation-High	1, 2, 3	1(a)	E	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.6	≤ [ ] gray
10.d Drywell Sump Drain HCW Radiation-High	1, 2, 3	1(a)	E	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.6	≤ [ ] gray
11. CIV Divisional Manual Initiation.	1, 2, 3, (j)	2 per division(d)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4 SR 3.3.1.4.7	NA
12. Reactor Core Isolation Cooling Isolation Actuation.					
12.a RCIC System Isolation Initiation.	1, 2, 3	2 per division(b)	B, C	SR 3.3.1.4.3 SR 3.3.1.4.4	NA

(Continued)

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 ECCS – Operating

LCO 3.5.1 Each ECCS subsystem and the Automatic Depressurization System (ADS) function of eight safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except ADS valves and RCIC are not required to be OPERABLE with reactor steam dome pressure ≤ 0.343 MPaG for ADS and ≤ 1.03 MPaG for RCIC.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or two ECCS subsystems inoperable provided RCIC is OPERABLE.	A.1 Restore ECCS subsystem(s) to OPERABLE status.	14 days
B. RCIC inoperable. OR RCIC and any one other ECCS subsystem inoperable.	B.1.1 Verify the CTG is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. (in less than 10) AND B.1.2 Verify the CTG circuit breakers are capable of being aligned to each of the ESF buses. OR B.2 Verify the ACIWA mode of RHR(C) subsystem is functional.	7 days 7 days AND Once per 8 hours thereafter 7 days (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.3 Restore ECCS subsystem(s) to OPERABLE status.	14 days
C. RCIC and any other two ECCS subsystems inoperable provided at least one HPCF subsystem is OPERABLE.	C.1.1.1 Verify the CTG is functional by verifying the CTG starts and achieves steady state voltage and frequency ~~within~~ in less than 10 2 minutes.	72 hours
	AND C.1.1.2 Verify the CTG circuit breakers are capable of being aligned to each of the ESF buses.	72 hours AND Once per 8 hours thereafter
	OR C.1.2 Verify the ACIWA mode of RHR(C) subsystem is functional.	72 hours
	AND C.2 Restore one ECCS subsystem to OPERABLE status.	7 days
D. Any three ECCS subsystems inoperable provided RCIC is OPERABLE.	D.1 Restore one ECCS subsystem to OPERABLE status.	3 days

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources – Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One of two offsite AC power sources to one ESF bus inoperable.	A.1	Verify affected ESF bus is powered from the other operable offsite AC circuit.	72 hours AND Once per 8 hours thereafter
	AND		
	A.2	Verify the CTG is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. in less than 10	72 hours AND Once per 7 days thereafter
	AND		
	A.3	Verify the CTG circuit breakers are aligned to the affected ESF bus.	72 hours AND Once per 8 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	AND		
	A.4	Restore inoperable offsite AC power to affected ESF bus.	30 days
B. One required offsite circuit inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s) with no power available from an OPERABLE offsite circuit inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no power available from an OPERABLE offsite circuit to one division concurrent with inoperability of redundant required feature(s)
	AND		
	B.3	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. in less than 10	72 hours
	AND		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Required Action C.3.1 or C.3.2 shall be completed if this Condition is entered. ----------	C.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
One required DG inoperable.	AND		
	C.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND		
	C.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	C.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		
	C.4	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. in less than 10	72 hours
	AND		
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One required offsite circuit inoperable. AND One required DG inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when Condition D is entered with no required AC power source to one division. ----------		
	E.1	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. in less than 10	12 hours
	AND		
	E.2	Verify the CTG circuit breakers are aligned to the ESF bus associated with the inoperable DG.	12 hours AND Once per 8 hours thereafter
	AND		
	E.3.1	Restore required offsite circuit to OPERABLE status.	72 hours
	OR		
	E.3.2	Restore required DG to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Two required DGs inoperable.	F.1	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. (in less than 10)	2 hours
	AND		
	F.2	Verify the CTG circuit breakers are aligned to one ESF bus associated with an inoperable DG and capable of being aligned to the other ESF bus associated with an inoperable DG.	2 hours AND Once per 8 hours thereafter
	AND		
	F.3	Restore one required DG to OPERABLE status.	72 hours
G. Required Action and Associated Completion Time of Condition A, B, C, D, E or F not met.	G.1	Be in MODE 3.	12 hours
	AND		
	G.2	Be in MODE 4.	36 hours
H. Three or more required AC sources inoperable.	H.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ---------- Verify each DG starts from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	As specified in Table 3.8.1-1

3744

4576

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by, and immediately follow, without shutdown, a successful performance of SR 3.8.1.2 or SR 3.8.1.7. ---------- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 5000 kW and ≤ [ ] kW. (7200)	As specified in Table 3.8.1-1
SR 3.8.1.4	Verify each day tank contains ≥ [ ] liters of fuel oil.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	31 days
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the storage tank to the day tank.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts from standby condition and achieves, in ≤ 20 seconds, 3744 voltage ≥ [6210] V and ≤ [7590] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz.	184 days 4576
SR 3.8.1.8	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify manual transfer of the [unit power supply] from the normal offsite circuit to each required alternate offsite circuit.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. *Credit may be taken for unplanned* events that satisfy this SR. ---------- Verify each DG operating at a power factor ≤ 0.9 rejects a load ≥ 540 kW for Division 1 and ≥ 1400 kW for Divisions 2 and 3, and: a. Following load rejection, the frequency is ≤ [ ] Hz; b. Within 3 seconds following load rejection, the voltage is ≥ [6210] V and ≤ [7590] V; and c. Within 3 seconds following load rejection, the frequency is ≥ 58.8 Hz and ≤ 61.2 Hz.	18 months
SR 3.8.1.10	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. *Credit may be taken for unplanned* events that satisfy this SR. ---------- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ [ ] V during and following a load rejection of a load ≥ [5000] V and ≤ [ ] kW.	18 months

4576

3744

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. 3. Credit may be taken for unplanned events that satisfy this SR. ----------	
	Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 20 seconds, 2. sequentially energizes auto-connected shutdown loads, 3. maintains steady state voltage ≥ [6210] V and ≤ [7590] V, 4. maintains steady state frequency ≥ [58.8] Hz and ≤ [61.2] Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	18 months

3744

4576

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2. 3. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 20 seconds after auto-start and during tests, achieves voltage ≥ [6210] V and ≤ [7590] V; b. In ≤ 20 seconds after auto-start and during tests, achieves frequency ≥ [58.8] Hz and ≤ [61.2] Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are sequentially energized from the offsite power system.	18 months

3744

4576

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.13	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1, 2, or 3. 2. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current.	18 months
SR 3.8.1.14	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance shall not be performed in MODE 1 or 2. 3. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG operating at a power factor ≤ 0.9, operates for ≥ 24 hours: a. For ≥ 2 hours loaded, ≥ 5225 kW and ≤ 5500 kW; and b. For the remaining hours of the test loaded ≥ 5000 kW and ≤ [ ].	18 months

7560

7920

7200

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	----------NOTES---------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 5225 kW and ≤ 5500 kW. (7560, 7920) Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts and achieves, in ≤ 20 seconds, voltage ≥ [6210] V and ≤ [7590] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz. (4576, 3744)	18 months
SR 3.8.1.16	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1, 2, or 3. 2. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	----------NOTES---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3. 3. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 20 seconds, 2. sequentially energizes auto-connected emergency loads, 3. achieves steady state voltage ≥ [6210] V and ≤ [7590] V, (3744, 4576) 4. achieves steady state frequency ≥ [58.8] Hz and ≤ [61.2] Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	----------NOTE---------- All DG starts may be preceded by an engine prelube period. ---------- Verify, when started simultaneously from standby condition, each Division 1, 2, and 3 DG achieves, in ≤ 20 seconds, voltage ≥ [6210] V and ≤ [7590] V and frequency ≥ [58.8] Hz and ≤ [61.2] Hz. 3744 4576	10 years during shutdown

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources – Operating

LCO 3.8.4 The Division I, Division II, Division III, and Division IV DC electrical power subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One DC electrical power subsystem (either Division I, II, or III) inoperable.	A.1	Determine OPERABLE DC electrical subsystems are not inoperable due to common cause failure.	2 hours
	AND		
	A.2	Declare affected required features inoperable.	2 hours
	AND		
	A.3	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. (in less than 10)	12 hours
	AND		
	A.4	Verify the CTG circuit breakers are capable of being aligned to the two unaffected ESF buses.	12 hours AND Once per 8 hours thereafter

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems – Operating

LCO 3.8.9 Divisions I, II, and III AC, Divisions I, II, III, and IV DC, and Divisions I, II, III, and IV AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Declare affected required features inoperable.	2 hours
	AND		
	A.2	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. (in less than 10)	12 hours
	AND		
	A.3	Verify the CTG circuit breakers are capable of being aligned to the OPERABLE 6.9 kV essential AC buses. (ESF buses)	12 hours AND Once per 8 hours thereafter
	AND		

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One DC electrical power distribution subsystem (either Division I, II, or III) inoperable.	D.1	Declare affected required features inoperable.	2 hours
	AND		
	D.2	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. in less than 10	12 hours
	AND		
	D.3	Verify the CTG circuit breakers are capable of being aligned to the two unaffected 6.9 kV essential AC buses. ESF buses	12 hours AND Once per 8 hours thereafter
	AND		
	D.4	Restore DC electrical power distribution subsystems to OPERABLE status.	72 hours AND 7 days from discovery of failure to meet LCO
E. Division IV DC electrical power distribution subsystem inoperable.	E.1	Declare affected required features inoperable.	2 hours

(continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Verify the combustion turbine generator (CTG) is functional by verifying the CTG starts and achieves steady state voltage and frequency within 2 minutes. (in less than 10)	1 hour
	AND		
	B.2	Verify the CTG circuit breakers are aligned to the 6.9 kV essential AC (ESF) bus associated with the inoperable required DG.	1 hour AND Once per 8 hours thereafter
	AND		
	B.3	Restore required DG to OPERABLE status.	14 days

(continued)

BASES

BACKGROUND
(Continued)

5. Shutdown Cooling System Isolation (continued)

The Functions used for RHR isolation/ECCS line-up initiation are:

- RHR Area Temperatures-High
- Reactor Vessel Water Level-Low, Level 3
- Reactor Vessel Steam Dome Pressure-High

OTHER ESF FUNCTIONS

The SSLC provides actuation Functions for various other ESF Functions:

1. Diesel Generator (DG) Initiation. The DG are initiated on high drywell pressure, low reactor water Level 1.5 and Level 1, or Essential 4.16 6/9 kV bus undervoltage (covered in LCO 3.3.1.4, "ESF Actuation Instrumentation").

2. Standby Gas Treatment Actuation. The Standby Gas Treatment (SGTS) system is automatically initiated on high drywell pressure, low reactor water Level 3, reactor building area exhaust air high radiation, or fuel handling area exhaust air high radiation.

3. Reactor Building Cooling Water/Service Water Actuation. This Feature is actuated on high drywell pressure, low Level 1, or 4.16 6/9 kV emergency bus undervoltage signals (covered in LCO 3.3.1.3).

4. Containment Atmospheric Monitoring System Start. The Containment Atmospheric Monitoring (CAM) system is automatically started on a high drywell pressure or low Level 1 signal.

5. Suppression Pool Cooling Actuation. Suppression pool cooling is automatically initiated on high suppression pool temperature.

6. Reactor Service Water System (RSW) Pump Trip and System Isolation Actuation. The RSW pumps and isolation of RSW system valves are initiated upon detection of high water level in the RCW/RSW heat exchanger rooms to provide flood protection (Ref. 11).

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (Continued)

4.d and e. ADS Division I/Division II ECCS Pump Discharge Pressure-High (permissive) (continued)

OPERABLE. Refer to LCO 3.5.1, "ECCS-Operating" for ADS Applicability Bases.

4.f. ATWS Manual ADS Inhibit

The ATWS Manual ADS Inhibit push button channels introduce signals into the ADS logic to provide manual ADS inhibit capability that is redundant to the automatic SENSOR CHANNELS. There is one push button for each ADS division trip system. Each pushbutton has two contacts. Each member of the SLU pair used to implement ADS acquires data from one of the contacts on the switch in its division (see Figure B 3.3.1.4-4).

The ATWS Manual ADS Inhibit Function is not assumed in any accident or transient analyses for the ABWR. However, the Function is retained for overall redundancy and diversity of the ADS function as required by the NRC in the plant licensing basis.

There is no Allowable Value for this Function since it is mechanically actuated based solely on the position of the push buttons. Four channels of this Function (two per ADS division) are required to be OPERABLE when ATWS is required to be OPERABLE. Refer to 3.3.1.3, "SLC and FWRB Actuation" for ATWS Applicability Bases.

5.a, 5.b, 7.d, 7.e. Divisions I, II, & III Loss of Voltage-6.9 kV and Degraded Voltage-6.9 kV.

4.16

The 6.9 kV busses are monitored to detect a loss of the offsite power or degraded bus conditions. If the bus voltage is less then required to support ESF features, the associated emergency Diesel-Generator (DG), provided as a back up to the offsite power source, is started. These SENSOR CHANNELS are provided to assure that there is sufficient power available to supply safety systems should they be needed. This Function is assumed in the loss of offsite power analysis of reference 3. The RCW/RSW system is also started on these Functions since it provides cooling for the diesels.

(continued)

BASES

4.16

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (Continued)

5.a. 5.b. 7.d. 7.e. Divisions I, II, & III Loss of Voltage-6/9 kV and Degraded Voltage-6/9 kV (continued)

4.16

The signals for this Function originate in undervoltage relays connected to each phase of the 6/9 kV bus. The phases are connected so that the loss of a single phase will cause two of the undervoltage relays to trip. The three undervoltage relays are combined in 2/3 logic so that a loss of any phase will cause starting of the associated DG while a failure in one of the relays will not cause a spurious start. A time delay is provided to prevent starting the DG due to transient conditions on the bus.

The undervoltage relay trip signals are transmitted to the SLU pair in the associated division via the EMS. Three channels of this Function are required to be OPERABLE in each of divisions I, II, & II in order to cause start of the associated DG on a valid signal. The Functions must be operable in MODES 1, 2, and 3 and in MODES 4 and 5 when any ECCS system is required to be OPERABLE as described in LCO 3.8.2, "AC Sources-Shutdown" and LCO 3.8.11, "AC Sources-Shutdown (Low Water Level)".

The Allowable values are selected high enough to detect degradation in offsite power to the point where it cannot supply the loads but low enough to assure that normal transients do not cause a spurious DG start. The degraded voltage Function uses a higher voltage set point but a longer time delay than the loss of voltage Function.

5.c Diesel Generator Initiation.

The Diesel Generators (DG) are used to supply emergency back up power to the ESF systems. The division II and III DGs receive a start signal when HPCF is initiated and all three divisions receive a start signal when the LPFL's are initiated. Each DG also receives a start signal from the divisional 6/9 KV bus monitors.

4.16

The DGs LOGIC CHANNELS are required to be OPERABLE in MODES 1, 2, 3, and in MODE 4 and 5 when the associated DG's are required to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (Continued)

7.a. Reactor Building Cooling Water/Service Water Initiation. (continued)

basis. The initiation occurs on high drywell pressure, low Level 1, or 6/9 KV emergency bus monitors. This Function is 4.16 not explicitly assumed in any accident or transient analysis for the ABWR. These signals, or suppression pool high temperature, also initiate shedding of non-essential loads.

This LOGIC CHANNEL Function is required to be OPERABLE in MODES 1, 2, & 3 and in MODE 4 and 5 when the DGs are required to be OPERABLE.

8.a. Containment Atmospheric Monitoring System Initiation.

The Containment Atmospheric Monitoring (CAM) system provides indications of the activity level of combustible gases and gamma activity in the containment following a LOCA. The CAM system's primary purpose is for post accident monitoring. The CAM system is automatically started on a high drywell pressure or low Level 1 signal. Two CAM systems are provided, one in division I and one in division II. The OPERABILITY of the CAM is not assumed in any ABWR transient or accident analysis.

The CAM automatic start LOGIC CHANNEL Function must be OPERABLE in MODES 1, 2 & 3 since these are the MODES where the CAM system is required to be operable.

9.a. Suppression Pool Cooling Initiation.

Suppression pool cooling is included to provide confidence that containment overpressure will not occur. Therefore, this Function is automatically initiated on high suppression pool temperature to minimize the burden on the operator. Automatic suppression pool cooling initiation is not assumed in the safety analysis but the instrumentation logic is processed in SSLC.

The suppression pool cooling LOGIC CHANNEL Function must be OPERABLE in MODES 1, 2, & 3 since these are the MODES where suppression pool cooling is required to be OPERABLE.

(continued)

BASES

ACTIONS
(Continued)

B.1, B.2.1, and B.2.2 (continued)

provides confidence that adequate plant protection capability is maintained. Action B.2.2 does not apply to features with no redundant alternate. The Completion Time for Action B.2.2 is as given for Action B.2.1.

Implementing either of the Actions B.2.1 or B.2.2 provides confidence that plant protection is within the design basis so no further Action is required.

These Actions apply to all LOGIC CHANNELS, except ADS, and the isolation initiation manual channels. They do not apply to the ADS LOGIC CHANNELS because they cannot be bypassed at the OUTPUT CHANNEL.

C.1

This Condition is provided to assure that appropriate action is taken for single or multiple inoperable channels that cause automatic or manual actuation of an ESF feature to become unavailable. However, automatic and manual initiation for redundant features are not affected.

Action C.1 restores the intended plant protection capability. The 1 hour Completion Time for Action C.1 provides some amount of time to restore automatic or manual actuation before additional Required Actions are imposed.

This Action applies to

- all LOGIC CHANNELS, except ADS
- isolation initiation manual channels
- ECCS Pump Discharge Flow—Low and Pressure—High channels
- HPCF Pump Suction Pressure—Low channel
- Divisions I, II, & III Loss of Voltage-6.9 kV and Degraded Voltage-6.9 kV. 4.16

(continued)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

The unit Class 1E AC Electrical Power Distribution System AC sources consist of the offsite power sources (normal preferred and alternate preferred) and the onsite standby power sources (Division I diesel generator (DG), Division II DG, and Division III DG). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system supplies electrical power to three divisional load groups, with each division powered by an independent Class 1E ~~6.9~~ 4.16 kV ESF bus (refer to LCO 3.8.9, "Distribution Systems – Operating"). Each ESF bus has two separate and independent preferred (offsite) sources of power and a dedicated onsite DG. Each ESF bus is also connectable to a combustion turbine generator (CTG). The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition.

Offsite power is supplied to each of the ~~6.9~~ 4.16 kV ESF buses from the transmission network via two electrically and physically separated circuits. In addition, the CTG may be substituted for the second (delay access) offsite source to any one ESF bus (for a limited duration) when the first (immediate access) offsite source to the ESF bus is from ~~the~~ a reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. The CTG may also be substituted for the second (delay access) offsite source for the three ESF buses (for a limited duration) when the first (immediate access) offsite source to each of the ESF buses is from its associated unit auxiliary transformer while the reserve auxiliary transformer~~s~~ (associated with the three ESF buses) ~~is~~ are out of service. These offsite AC electrical power circuits are designed and located so as to minimize to the extent practicable the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power

(continued)

BASES

BACKGROUND (continued)

system and circuits to the onsite Class 1E ESF buses is found in DCD Tier 2, Chapter 8 (Ref. 2).

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, controls, and control power supplies required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es). Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Initiating signals (i.e., load shedding and buses-ready-to-load) for returning certain plant loads to service are generated by the control system for the electrical power distribution system. Individual timers for each major load are reset and started by their electrical power distribution system signals and/or LOCA signals. After the initiating signals are received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service in a preset sequence via timer delays on each load.

4.16

The onsite standby power source for each 6/9 kV ESF bus is a dedicated DG. A DG starts automatically on loss of coolant accident (LOCA) signal (i.e., signal generated from low reactor water level and high drywell pressure that are arranged in two-out-of four logic combinations) or on an ESF bus undervoltage signal (refer to LCO 3.3.1.4, "ESF Actuation Instrumentation"). In addition, power can be supplied to any one ESF from the CTG (for a limited duration) when a DG is inoperable.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Ratings for DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating for each DG is 5000 kW @ 0.8 power factor, with 10% overload permissible for up to 2 hours in any 24 hour period.

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BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in DCD Tier 2, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), ssume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources (not including the CTG) is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

AC sources satisfy the requirements of Criterion 3 of the NRC Policy Statement. In addition, the CTG may be substituted for the second (delay access) offsite source to any one ESF bus when the first (immediate access) offsite source is from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. The CTG may also be substituted for the second (delay access) offsite source for the three ESF buses (for a limited duration) when the first (immediate access) offsite source to each of the ESF buses is from its associated unit auxiliary transformer while the reserve auxiliary transformer (associated with the three ESF buses) is out of service. The CTG may also be used to substitute (for a limited time) for an inoperable DG. With this substitution, the AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded.

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BASES

LCO

Two qualified offsite circuits between the offsite transmission network and the onsite Class 1E Distribution System that consists of three separate and independent divisions (Divisions I, II, and III) each backed by its own dedicated and independent DG, ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, the CTG may be utilized as a temporary substitution for the second (delayed access) qualified offsite circuit when the first (immediate access) qualified offsite circuit to any one ESF bus (immediate access) offsite source is from the reserve auxiliary transformer while the unit auxiliary transformer associated with the ESF bus is out of service. With this temporary substitution, the two qualified offsite circuits between the offsite transmission network and the onsite Class 1E Distribution System that consists of three separate and independent divisions (Divisions I, II, and III) each backed by its own dedicated and independent DG, also ensure availability of the required power to shutdown the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. a

Qualified offsite circuits are the normal and alternate preferred power circuits that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the unit. In addition, the temporary substitution of the CTG is described in DCD Tier 2, Chapter 8 and is part of the licensing basis for the unit.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads within the assumed load sequence intervals during an accident, while connected to the ESF buses. The normal preferred circuit consists of the switching station breaker to the main transformer, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses including feeder breakers at the 6/9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve auxiliary transformer and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses including feeder breakers at the 6/9 kV ESF buses. S S 4.16

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BASES

LCO
(continued)

Each DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with engine hot, DG in standby with engine at ambient conditions, and DG operating in parallel test mode.

The CTG, when used as a temporary substitute for the second offsite source or for an inoperable DG to any one ESF bus, must be capable of starting, accelerating to required speed and voltage, and of being manually configured to provide power to the ESF bus. This sequence must be accomplished in less than 10 ~~within 2~~ minutes. The CTG must also be capable of accepting required loads, must be capable of maintaining rated frequency and voltage, and accepting required loads when connected to the ESF bus.

Proper sequencing of loads is a required function for both DG and offsite circuit OPERABILITY.

The AC sources are separate and independent. For the DG AC sources, the separation and independence are complete. For the offsite AC sources (including the CTG as an offsite source), the separation and independence are to the extent practicable. For the offsite (including the CTG) to DG AC sources, the separation and independence are to the extent practicable.

Offsite circuit OPERABILITY includes the normal offsite source supplying two of three AC divisions and the alternate offsite source supplying the third AC division. Other configurations make an offsite circuit inoperable.

The AC sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

(continued)

BASES

ACTIONS (continued)

B.3, B.4, and B.5

If Condition B is entered, Required Action B.5 allows 14 days to restore the inoperable offsite circuit to OPERABLE status, provided the combustion turbine generator (CTG) is verified functional through testing within 72 hours and its capability of being aligned to any of the three ESF buses is verified, initially within 72 hours, and once per 8 hours thereafter. This 14-day Completion Time is reasonable because it accounts for the reliability and convenience of the CTG. Since the CTG can be aligned as a temporary backup offsite source, there are sufficient offsite sources available if Required Actions B.3 and B.4 are completed. The LCO is not completely satisfied at this point, but the AC electrical power system is verified to be sufficiently reliable to allow for the 14-day Completion Time of Required Action A.5. The 14-day Completion Time is also reasonable because the capabilities of the remaining AC sources are adequate for this time period, and because of the low probability of a DBA occurring during this time period. See the discussion for Required Action C.6 for additional justification of this Completion Time.

If the CTG cannot be made available to function as a temporary backup offsite circuit within 72 hours, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation in the applicable modes may continue as described by Condition B for a period that should not exceed 72 hours. Therefore, if Required Actions B.3 and B.4 cannot be completed within 72 hours of entering Condition B, then Required Actions G.1 and G.2 must be followed. Upon restoring the offsite circuit to OPERABLE status, the LCO is met, Conditions B and G are exited, and operation may continue.

4.16 Should the CTG no longer be functional or capable of being aligned to a 6/9 kV AC ESF bus subsequent to the 72-hour period following initial entry into Condition B, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action B.4 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the offsite circuit to OPERABLE status.

(continued)

BASES

ACTIONS (continued)

B.3, B.4, and B.5

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

[12.42] kV → [6210] V
[15.18] kV → [7590] V
in less than 10 → within 2

The 14-day Completion Time of Required Action B.5 assumes sufficient offsite power remains to power the minimum loads needed to respond to analyzed events. It also assumes that the CTG may be utilized if needed. Should two divisions be affected, the 1-day Completion Time of Required Action B.5 is conservative with respect to the Regulatory Guide assumptions supporting a 1 day Completion Time for both offsite circuits inoperable (addressed by Condition D). With only one offsite circuit, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In Condition B, however, the remaining OPERABLE offsite circuit, DGs, and the CTG are adequate to supply electrical power to the onsite Class 1E distribution system.

The 14-day Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action B.5 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, a DG is inoperable and that DG is subsequently returned to OPERABLE status, the LCO may already have been not met for up to 14 days. This situation could lead to a total of 28 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored to OPERABLE status, and an additional 14 days (for a total of 42 days) allowed prior to complete restoration of the LCO. The 15-day Completion Time provides a limit on the time allowed in a specified Condition after discovery of failure to meet the LCO.

(continued)

BASES

ACTIONS (continued)

C.3.1 and C.3.2 (continued)

determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition F of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action C.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DGs.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

C.4, C.5, and C.6

If Condition C is entered, Required Action C.6 allows 14 days to restore the inoperable DG to OPERABLE status provided the CTG is verified functional through testing within 72 hours, and its circuit breakers are verified to be aligned to the affected ESF bus initially within 72 hours and once per 8 hours thereafter. This 14-day Completion Time is reasonable because of the reliability and convenience of the CTG, the low probability of a DBA occurring during this time period.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

[12.42] kV

[15.18] kV

in less than 10

If the CTG can not be made available to function as a temporary onsite divisional backup to preferred offsite power, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition C for a period that should not exceed 72 hours. Therefore, if Required Actions C.4 and C.5 cannot be completed within 72 hours of entering Condition B, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable DG to

(continued)

BASES

ACTIONS (continued)

E.1 and E.2 (continued)

Time is reasonable because of the reliability and convenience of the CTG, the capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this time period.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

[12.42] kV

[15.18] kV

in less than 10

If the CTG can not be made available to function as a temporary onsite divisional backup power source, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition E for a period that should not exceed 12 hours. Therefore, if Required Actions E.1 and E.2 cannot be completed within 12 hours of entering Condition E, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable offsite circuit or DG to OPERABLE status, the LCO is met, Conditions E and G are exited, and operation may continue.

Should the CTG no longer be functional or not aligned to an ESF bus subsequent to the 12-hour period following initial entry into Condition C, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action E.2 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the offsite circuit or the DG to OPERABLE status.

The once-per-8-hour Completion Time of Required Action E.2 is necessary to keep a check on the proper alignment of the CTG's circuit breakers and thus the capability of supplying power from the CTG to the 6.9 kV essential AC bus associated with the inoperable DG.

4.16 kV ESF

F.1

If Condition F is entered, Required Action F.3 allows 72 hours to restore one DG to OPERABLE status provided the CTG is verified functional through testing within 2 hours, and

(continued)

BASES

ACTIONS (continued)

F.1 (continued)

4.16

its circuit breakers are aligned to one affected 6.9 kV ESF bus associated with an inoperable DG and capable of being aligned to the other 6.9 kV ESF bus associated with an inoperable DG, initially within 2 hours and verified once per 8 hours thereafter. This 2 hour Completion Time is reasonable because of the reliability and convenience of the CTG, the capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this time period.

4.16

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

[12.42] kV

[15.18] kV

in less than 10

If the CTG can not be made available to function as a temporary onsite divisional backup power source, the configuration of the AC sources is as described in Regulatory Guide 1.93 (Ref. 6), which states that operation may continue as described in Condition F for a period that should not exceed 2 hours. Therefore, if Required Actions F.1 and F.2 cannot be completed within 2 hours of entering Condition F, then Required Actions G.1 and G.2 must be followed. Upon restoring the inoperable one DG to OPERABLE status, the LCO is met, Conditions F and G are exited, and operation may continue.

Should the CTG no longer be functional or not aligned to one ESF bus or not capable of being aligned to the other ESF bus subsequent to the 2-hour period following initial entry into Condition F, Condition G again applies and Required Actions G.1 and G.2 must be followed. Anytime the 8-hour Completion Time of Required Action F.2 is not met during this extension period, Condition G must be entered. Condition G can then only be exited by restoring the DG to OPERABLE status.

The once-per-8-hour Completion Time of Required Action F.2 is necessary to keep a check on the proper alignment of the CTG's circuit breakers and thus the capability of supplying power from the CTG to the ESF buses associated with the inoperable DGs.

(continued)

BASES

ACTIONS (continued)

G.1 and G.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

H.1

Condition H corresponds to a level of degradation in which all redundancy in the AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages under simulated accident conditions. The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3), and Regulatory Guide 1.137 (Ref. 9).

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 6210 V is 90% of the nominal 6.9 kV output voltage. This value, which is specified in ANSI C84.1 (Ref. 10), allows for voltage drop to the terminals of 6600 V motors whose minimum operating voltage is specified as 90%, or 5980 V. It also allows for voltage drops to motors and other equipment down through the 200 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified

3744

4.16

4000

3600

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

maximum steady state output voltage of 7590 V is equal to the maximum operating voltage specified for 6600 V motors plus voltage drop from the source to the loads. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 6600 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

4576

4000

4000

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2 and SR 3.8.1.7

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs have been modified by Notes (Note 1 for SR 3.8.1.7 and Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.6

testing. In such a case, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR should be modified to reflect individual designs.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Manual transfer of each ~~6.9~~ 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The manual transfer should be performed using the DG to carry the loads (i.e., not a dead bus transfer). The 18 month Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed on the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge entwined steady state operation and, as a result, plant safety systems. Note 2 acknowledges that credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of

(continued)

BASES

LCO
(continued)

Systems – Shutdown," ensures that all required loads on Division I, Division II, and Division III are powered from offsite power. One or more OPERABLE DG(s) available in standby to supply electrical power to required OPERABLE features via the associated Engineered Safety Feature (ESF) buses that are required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DG(s) ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel drain down, and loss of decay heat removal).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage while connected to ESF bus(es), and of accepting required loads during an accident. The qualified offsite circuit is either the normal or alternate preferred power circuits to AC Electric Power Distribution System that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the plant. The normal preferred circuit consists of the switching stations breaker to the main transformers, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6/9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve transformer and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6/9 kV ESF buses.

4.16 4.16 S S 4.16

Each required DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

maintaining electrical power sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC or all onsite AC electrical power; and

b. A worst case single failure.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of the NRC Policy Statement.

LCO

The inverters ensure the availability of AC electrical power for the Class 1E CVCF loads required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS, MSIV logic and controls, NMS, and PRM, is maintained. Each of the four inverters has a 125 V battery backup power source to ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV and 480 V safety buses are de-energized. 4.16

OPERABLE inverters require that the AC vital bus be powered by the inverter via an inverted DC voltage. This assumes correct DC voltages are applied from the AC to DC rectified and 125 V DC power supplies, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. If the vital AC bus is powered from the AC power supply through the 480 V/120 V bypass transformer, or power is available to the inverter from only its AC source, then the inverter is considered inoperable.

(continued)

BASES (continued)

LCO

The inverters ensure the availability of AC electrical power for the RPS and ECCS instrumentation and controls required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or postulated DBA.

Maintaining the required inverter(s) OPERABLE ensures the availability of sufficient inverter power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents and inadvertent reactor vessel drain down). Each inverter has a 125 V battery backup power source to ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6/9 kV safety buses are de-energized. 4.16

OPERABLE inverters require the AC vital bus be powered by the inverter through inverted DC voltage. This assumes correct DC voltages are applied from the AC to DC rectified and 125 V DC power supplies, a correct AC voltage is at the output, and these voltages are within the design voltage and frequency tolerances. If the vital AC bus is powered from the AC power supply through the 480 V/120 V bypass transformer or power is available to the inverter from only its AC source, then the inverter is considered inoperable.

APPLICABILITY

The inverters required to be OPERABLE in MODES 4 and 5 and also any time during movement of irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent drain down of the reactor vessel;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

(continued)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems – Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided by division into three independent AC and four independent DC and AC vital bus electrical power distribution subsystems.

The primary AC distribution system consists of each 6.9 kV Engineered Safety Feature (ESF) bus that has two separate and independent offsite sources of power, as well as a dedicated onsite diesel generator (DG) source. Each 6.9 kV ESF bus is normally connected to a preferred source. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 6.9 kV ESF buses. Control power for the 6.9 kV breakers is supplied from the Class 1E batteries. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources – Operating," and the Bases for LCO 3.8.4, "DC Sources – Operating."

4.16 4.16

The secondary plant AC distribution system includes 480 V ESF load centers and associated loads, motor control centers, and transformers. Each 480 V AC MCC is powered from its divisional 6.9 kV ESF Bus via a 6.9 kV/480 V transformer.

4.16

The 120 V AC vital buses A10, B10, C10, and D10 (Divisions I, II, III, and IV respectively) are arranged in four load groups and are normally powered from a divisional 480 V AC motor control center (MCC) via a rectifier, an inverter, and a static switch. Divisions I, II, and III are normally powered from Division I, II, and III 480 V AC MCCs, respectively. Division IV is normally powered from a Division II 480 V AC MCC since there is no fourth division of 480 V AC. However, each of the four DC electrical power distribution subsystems (including Division IV) is backed up by its own battery bank and will automatically supply power (via the inverter) in the event of low voltage output from the rectifier (which would occur, for example, if the 480 V AC divisional power is lost). The Bases for LCO 3.8.7, "Inverters- Operating," describe the use of the four DC subsystems. In the event of an inoperable inverter, an alternate power supply for each 120 V AC vital bus is a divisional Class 1E 480 V/120 V bypass transformer powered

(continued)

BASES

LCO

The required AC, DC, and AC vital bus power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. All divisional AC, DC, and AC vital bus electrical power primary distribution subsystems are required to be OPERABLE.

Maintaining the three Divisions of AC and the four Divisions of DC and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF systems is not defeated. Any two of Divisions I, II, and III of the AC, DC, and AC vital distribution systems are capable of providing the necessary electrical power to the associated ESF components. In addition, any two of Divisions I, II, III, and IV of the DC and AC vital distribution systems except the combination of Divisions II and IV systems (which are vulnerable to common failure because of their common AC power supply) are capable of providing the necessary electrical power to the associated RPS and ECCS safety system logic and control system components. Therefore, a single failure within any system or within an electrical power distribution subsystem does not prevent safe shutdown of the reactor.

OPERABLE AC, DC, and AC vital bus electrical power distribution subsystems require the associated buses (listed in Table B 3.8.9-1) to be energized to their proper voltages. With the exception of a special set of manual interlocks through the spare battery chargers, there are no tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems. This prevents any electrical malfunction in any power distribution subsystem from propagating to a redundant subsystem, which could cause the failure of the redundant subsystem and a loss of essential safety function(s). It does not, however, preclude redundant Class 1E 6/9 kV buses from being powered from the same offsite circuit. 4.16

(continued)

Table B 3.8.9-1 (page 1 of 1)
AC, DC, and AC Vital Bus Electrical Power Distribution System

SYSTEM	BUS TYPE AND VOLTAGE	DIVISION 1*	DIVISION 2*	DIVISION 3*	DIVISION 4*
AC Buses	4.16 kV ESF Bus 6900 V	M/C E	M/C F	M/C G	Not Applicable
	Power Center 480 V	P/C E10 P/C E20	P/C F10 P/C F20	P/C G10 P/C G20	
	Motor Control Center 480 V	C/B E110 C/B E111 C/B E112 C/B E113 C/B E120 C/B E260	C/B F110 C/B F111 C/B F112 C/B F113 C/B F120 C/B F260	C/B G110 C/B G111 C/B G112 C/B G113 C/B G120 C/B G260	
	Distribution Panel 120 V	IP A10 IP A20	IP B10 IP B20	IP C10 IP C20	
DC Buses	Motor Control Center 125 V	DC MCC A1	-	-	-
	Distribution Panel 125 V	DC A10 DC A20	DC B10 DC B20	DC C10 DC C20	DC D10** DC D20**
AC Vital Buses	CONSTANT VOLTAGE, CONSTANT FREQUENCY DISTRIBUTION PANEL 120 V	A11 A21	B11 B21	C11 C12	D11*** D12***

* Each division of the AC, DC, and AC vital bus electrical power distribution system is a subsystem.
** The battery charger for Division 4 DC subsystem is powered by a Division 2 480 V AC motor control center.
*** The normal power source for the Division 4 AC vital bus subsystem is a Division 2 480 V AC motor control center.

BASES

LCO

One offsite circuit capable of supplying onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems – Shutdown," ensures that all required loads on Division I, Division II, and Division III are powered from offsite power. Two or more OPERABLE DGs available in standby to supply electrical power to required OPERABLE features via the associated Engineered Safety Feature (ESF) buses that are required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DGs ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents, reactor vessel drain down, and loss of decay heat removal).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage while connected to ESF buses, and of accepting required loads during an accident. The qualified offsite circuit is either the normal or alternate preferred power circuits to the AC Electric Power Distribution System that are described in DCD Tier 2, Chapter 8 and are part of the licensing basis for the plant. The normal preferred circuit consists of the switching stations breaker to the main transformers, the generator breaker, the disconnect links to the unit auxiliary transformers, and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6/9 kV ESF buses. The alternate preferred circuit consists of the switching station breaker to the reserve transformer and the circuit path from the offsite transmission network to all of the 6/9 kV ESF buses required by LCO 3.8.10 including feeder breakers at the 6/9 kV ESF buses.

Each required DG must be capable of starting, accelerating to required speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 20 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions such as: DG in standby with the engine hot, DG in standby with the engine at ambient conditions,

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With one required DG inoperable, 14 days are allowed for restoring the DG to OPERABLE status provided the combustion turbine generator (CTG) is verified to be functional through testing within 1 hour and its breakers are verified to be aligned to the ESF bus associated with the inoperable DG within 1 hour and every 8 hours thereafter. As long as the CTG is available to serve as a backup to the inoperable DG, shutdown activities (that would otherwise be prohibited in a low water level condition) in MODES 4 and 5 are permitted. This 14-day Completion Time is considered reasonable because of the reliability and convenience of the CTG, the low probability of a shutdown transient (e.g., loss of decay heat removal) occurring during this time period, and the availability of at least one other OPERABLE DG.

The CTG is considered functional when the requirements of DCD Tier 2, Section 9.5.13.19 are satisfied and the CTG is verified to start from standby conditions and achieves steady state voltage ≥ [6210] V and ≤ [7590] V, and frequency ≥ [58.8] Hz and ≤ [61.2] Hz within 2 minutes.

[12.42] kV

[15.18] kV

in less than 10

C.1, C.2, C.3, C.4, and C.5

When a Required Action and Completion Time of Condition B are not met (either the CTG is not functional or alignable to the required ESF bus, or one DG cannot be restored to OPERABLE status), or when two or more of the required DGs are inoperable, the required diversity of AC power sources to plant safety systems is not available. Required Actions C.1, C.2, and C.3, therefore, suspend CORE ALTERATIONS, movement of irradiated fuel assemblies in the secondary containment, and activities that could potentially result in inadvertent draining of the reactor vessel. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to initiate action immediately to restore the required DG(s) OPERABLE status and to continue this action until restoration is accomplished in order to provide the required diversity of AC power sources to plant safety systems.

(continued)